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Production and storage of non-carbon fuels for the Shetland Islands maritime sector

Report for the Department of Transport

Final report on work package 3 of NEPTUNE for
Department for Transport

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1 Introduction

The Neptune project is an innovation project winner of the Clean Maritime Demonstration Competition (CMDC). As a winner of the CMDC, the project is receiving support funding from the Department for Transport (DfT) in partnership with Innovate UK. The project is being delivered by a consortium managed by the University of Strathclyde and include Ricardo, Babcock and Shetland Islands Council.

The project will develop a desk-based decision modelling and support system tool that will help to analyse, scope and develop plans for supporting the Shetland Islands' maritime sector energy transition. Work package three of the project aims to assess the requirements of hydrogen and ammonia production and port-side storage capacity.

This report represents of the work package's objectives to:

- estimate the current and future energy and fuel demands of the Shetland marine sector;
- assess the island's renewable energy potential to provide zero carbon fuels to meet the demand of the local maritime industry;
- determine what size of fuel production plants are required to facilitate the electrolytic zero carbon marine fuels; and

the land-side facilities required to keep the sector reliably refuelled.

1.1 The Shetland islands

The Shetland islands are an archipelago of islands north of Scotland with abundant renewable energy resource. The Shetland islands' geographical location exposes them to powerful tides and strong winds from the North Atlantic sea. Due to its remote location and the low power demand of the Shetland islands' 23,000 inhabitants, this resource has largely gone unexploited until now. A 443MW wind farm called Viking is being constructed and three 100kW tidal stream turbines piloted. A 600MW interconnector is also under construction to export the excess energy back to the mainland. The difference in capacity between the interconnector and generation gives prospect to future generation projects under development. Conceptualised projects give the islands a maximum potential of nearly 14GW.

The most prominent economic sectors in the Shetland islands are oil and gas, fishing, and aquaculture. All three of these sectors are heavily reliant on the maritime sector to operate successfully. The islands are also interconnected with each other and the mainland with ferries capable of transporting vehicles. The fuel demand of marine gas oil equates to 39% of the island's primary energy demand [1].

In their Hydrogen Action Plan the Scottish government have flagged the Shetland islands as a potential location for a regional hydrogen hub recognising their wind generation potential and established energy sector supply chain.

1.2 Orion project

The Orion project is simultaneously underway to the Neptune project. It aims to provide Shetland with secure and affordable clean energy whilst developing a new energy export industry. ORION strategic partners Shetland Island Council (SIC), Net Zero Technology Centre (NZTC), University of Strathclyde and Highlands and Islands Enterprise (HIE) are working with industry and key stakeholders to evaluate opportunities to transition Shetland from an established oil and gas centre to a renewable energy hub.

The Orion project has three key aims:

- Create renewable hydrogen for export at industrial scale by harnessing offshore wind power
- Transform Shetland's current dependency on fossil fuels to affordable renewable energy
- Enable offshore oil and gas sector just transition to net zero by electrification

Orion has clear synergies with the Neptune project. The production infrastructure has the opportunity provide renewable electrofuels (efuels) to the island's economy including the maritime sector.

2 Maritime demand

This study aims to estimate how much zero-carbon fuel production is required to meet the islands' maritime sector demand. The first step in doing so is to conduct a comprehensive assessment of the Shetland islands' maritime sector demand. The Neptune project team determined that there were six distinct categories of vessels operating on the island. Their size, utilisation, duty cycle, refuelling patterns and decarbonisation options vary significantly. The consortium sent data collection sheets and hosted consultations with representatives of each of the categories to gain a deeper understanding of vessel operations. The locations of these vessels around the islands is shown below:

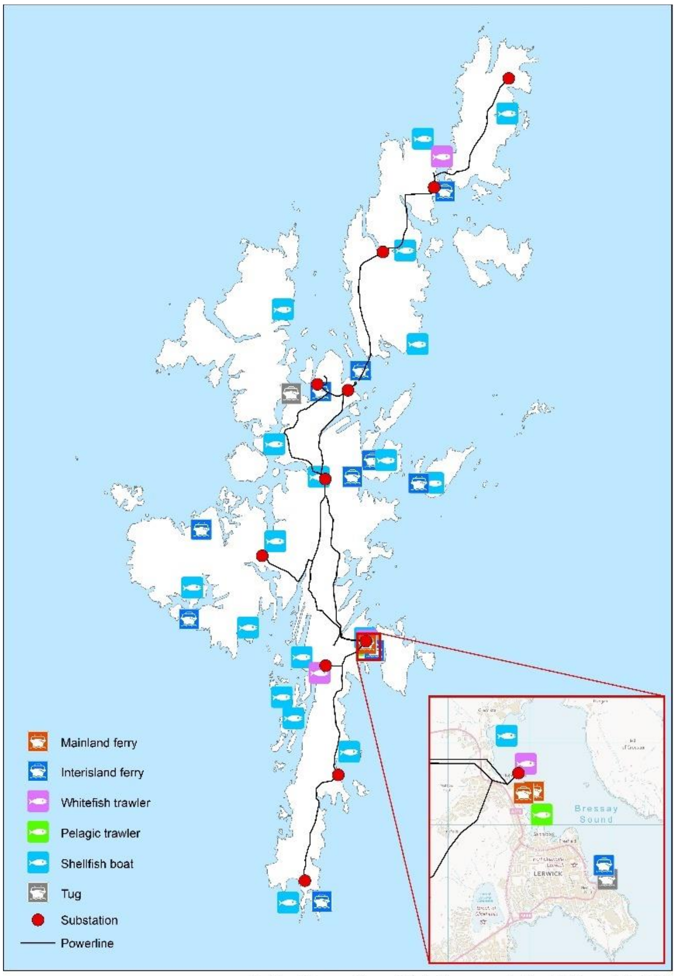

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Figure 2-1 Location of vessels around the Shetland Islands

This section uses those learnings to profile the operation of the vessel categories before conducting a multi-criteria analysis to determine what low-carbon fuels would be appropriate solutions. Finally, demand of low-carbon fuels is quantified across 5-year time intervals.

2.1 Vessel categories profiles

2.1.1 Scottish mainland ferries

There are four ferries transiting between the Aberdeen on the Scottish mainland and Lerwick on Shetland. The vessels are owned by CalMac Ferries Ltd and operated by NorthLink ferries. The ferries are essential for delivering provisions to the island by transporting commercial freight and are a key route of access for tourism.

These vessels refuel in their homeport of Aberdeen, therefore are technically out of the scope of the Shetland Islands maritime sector fuel demand. However, the Shetland Islands' impressive renewable resources gives significant potential for locally produced efuels to be cost-competitive with efuels produced on the mainland, offering an economic opportunity for the Shetland Islands. Therefore it is assumed that when these vessels transition to efuels they begin regularly refuelling from the Shetland Islands rather than the Scottish mainland, significantly increasing the overall energy demand of the maritime sector.

2.1.1.1 Roll-On Passenger

MV Hjatland and MV Hrossey are Roll-On Passenger (ROPAX) vehicles that carry freight, road vehicles and passengers. They are built to the same specification to carry up to 600 passengers and 95 Passenger Car Units (PCUs). They are each 122 metres long and powered by four 5.4MW internal combustion engines. Between them, they operate a daily departure service to Shetland and occasionally stopping at Orkney. Their typical amount of fuel consumed before each refuelling is ~70 m^3 of Marine Gas Oil (MGO). They are due for replacement between 2030 and 2035.

Figure 2-2: Passenger ferry MV Hjatland [2]

2.1.1.2 Roll-On Roll-Off

Two more vessels, MS Helliar and MS Hildasay, are Roll-On Roll-Off (RORO) ferry vessels whose main function is to deliver freight. They are built to the same specification to carry up to 88 trailers and 12 passengers. They are 122 metres long and powered by two 3.7MW internal combustion engines. Between them, they operate a bi-weekly departure service. Their typical amount of fuel consumed before each refuelling is ~75m^3 of Marine Gas Oil (MGO). They are due for replacement in 2026 by RORO vessels powered by Liquified Natural Gas (LNG). Stakeholder consultation revealed that LNG is an interim fuel solution and the vessels have been designed for retrofit to Ammonia at a later date when supply chains are practical, and regulation incentivises the transition.

Figure 2-3: Freight ferry MS Hildasay [3]

2.1.2 Interisland ferries

There are 12 ferries connecting the populations of the Shetland Islands together. All but one are owned and operated by Shetland islands council. The route between Foula island and Walls on Shetland is operated by a private company. The ferry vessels regularly sail the specific route they are assigned to and occasionally sail additional routes if required. MV Fivla is a relief vessel that will temporarily replace vessels being serviced. Figure 2-4 shows the vessels and their respective ferry routes.

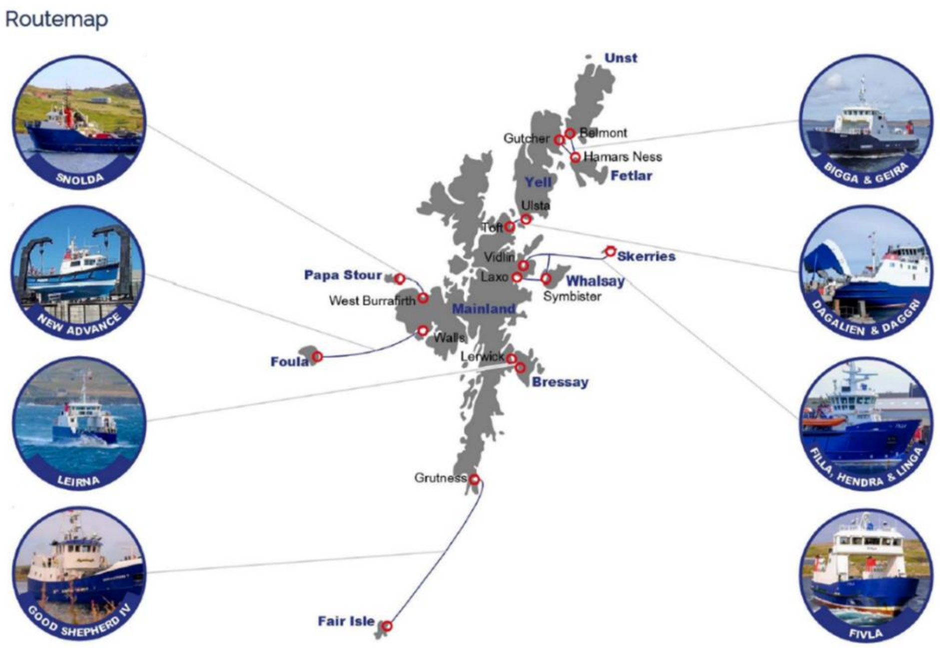


Figure 2-4: map of inter-island ferries

The distance and frequency of routes vary significantly. MV Daggri and MV Dagalien sail the shortest route between Shetland and Yell across 2.6 nautical miles and taking approximately 10 minutes. The route sails up to 25 trips a day and carries up to 144 passengers and 31 PCUs.

In comparison, MV Good Shephard sails the longest route between Shetland and Fair isle across 24.8 nautical miles and taking approximately 2 hours and 40 minutes. The route sails just once a week and carries up to 12 passengers.

Some of the routes are being considered for a fixed crossing that would see the islands connected by bridges or tunnels. This outcome would eliminate the fuel requirement for the crossing it replaces. However, these decisions are still in a conceptual phase so have been disregarded for the study.

All inter-island ferry vessels are currently refuelled by fuel delivery trucks.

2.1.3 Offshore service vessels

2.1.3.1 Offshore oil and gas sector

Offshore services vessels (OSVs) provide support to the offshore oil and gas sector infrastructure to the west and east of the Shetland Islands. These vessels frequently moor in Lerwick to change crews, gather supplies, and refuel. They vary significantly in purpose and size, types of vessels include:

- Supply vessels
- Standby vessels
- Seismic boats
- Diving boats
- Anchor handlers
- Survey vessels

It is expected that in future these vessel types will change as exploration of oil and gas ceases, decommissioning increases and offshore wind installations and maintenance gather pace.

2.1.3.2 Offshore wind sector

Offshore service vessels related to the construction and decommissioning of wind farms are expected to operate around the Shetlands Islands for inconsistent but multi-year tenures. These vessels serve clients internationally and need to be prepared to cross seas to reach their operation destination. They are likely to refuel in the Shetland Islands when operating in the area. Refuelling needs will be context dependent and require forward planning in advance of each project to ensure needs can be fulfilled.

Vessels related to maintenance will have consistent, longer-term fuel demands on the Shetland Islands. Planned maintenance vessels are relatively smaller vessels that operate in the summer months when conditions are safer. Unplanned maintenance can occur at any time and can require larger support vessels to replace parts.

2.1.4 Tugs

There are six tugs operating on the islands. Two tugs operate in Lerwick port and are owned and managed by Lerwick Port Authority. The remaining four tugs operate in Sullum Voe oil terminal and are owned and operated by Shetland Islands Council. The Sullom Voe tugs are significantly larger than Lerwick tugs as they regularly support large oil transport vessels visiting the island.

The tugs' core use is to assist less manoeuvrable vessels by pulling them with a tow line or pushing them with direct contact. Tugs are required to have high power engines to provide the force necessary to move much larger and heavier vessels. This requirement means that tugs have periods of intense operation that consume significant quantities of fuel relative to other vessels of similar size. Tugs are relatively small, to maximise manoeuvrability.

The tugs of Sullom Voe assist two to three vessels a week so have low utilisation of 350 hours per year. However, as discovered during stakeholder consultation, the tugs needs to be available to operate for more infrequent circumstances including:

- Rescue – tugs are used as recovery vessels for waters surrounding the islands which can take up to a day's travel to the situation area and then tow the vessel in distress to a safe place;
- Firefighting – tugs are capable of firefighting to industry standard FiFi1 and are required to have a minimum of two fire monitors capable of throwing water over 120m and to a height of 45m. Depending on the type of fire, they can take a substantial time to extinguish. The on-board water pumps use electricity provided by the engine alternator and are energy demanding;
- Pushing-up against crosswinds – tugs need to be able to counter forces to moored vessels for extended periods in strong gales; and
- Drydock servicing – there are no drydocks on Shetland that are able to service the tugs operating at Sullom Voe. They currently transit back to mainland Scotland for servicing.

Their operational needs require them to carry significant amounts of fuel but their low utilisation means that they refuel irregularly. Trucks filled with MGO park on the jetty alongside the tugs and refuel them with a dispensing hose.

Figure 2-5: The harbour pilot boat Knab tows the Rosebloom to Lerwick [4]

2.1.5 Fishing fleet

Fishing is one of the Shetland Islands' largest economic sectors. Statistics from the Shetland Fish Producers Association state that 18% of all of the fish landed in the UK was landed in Shetland. There are three different types of vessel that make up the industry that are explored in more detail.

2.1.5.1 Pelagic trawlers

There are eight pelagic fishing vessels registered in Shetland. The vessels have approximately 75 metre hulls and are powered by large multi-megawatt engines to counteract the drag of a trawling net. The annual fuel demand of these vessels is amongst the highest of the island. On fishing trips, they may travel great distances to fishing grounds and spend multiple days at sea. The fish they catch are migratory species and therefore the timing of trips and the vessel's fuel demands are highly seasonal. Trawlers return to Lerwick port fish market to offload their catch. Returning to port also gives them the opportunity to refuel before returning to sea. The trawlers have space constraints on-board with equipment on-deck and space for storing fish in the hold is maximised. Lower density efuels will be a challenge for this vessel category.

Figure 2-6: Pelagic trawler LK 62 Research [5]

2.1.5.2 Whitefish trawlers

There are 22 whitefish trawlers operating from the Shetland islands. They are significantly smaller than the Pelagic trawlers with hull lengths averaging 24 metres. The trawlers catch demersal fish that remain in UK waters year-round and there is no evidence of seasonality to their demand. Shetland's fishery statistics conducted by University of the Highlands and Islands Shetland show that they offload their catch into various ports around the island. The largest three ports that receive whitefish catch are Lerwick, Scalloway and Cullivoe. Despite having more vessels, comparing the gross weight of the whitefish trawlers to the pelagic trawlers shows they have a significantly lower fuel demand overall.

Figure 2-7: Whitefish trawler LK 253 Ocean Challenge [6]

2.1.5.3 Shellfish and inshore boats

According to the Shetland Fisherman yearbook, there are 101 shellfish boats and 22 inshore boats that operate from the Shetland islands. They are significantly smaller than the pelagic and whitefish trawlers with an average hull length of 9 metres. The shellfish boats tend to their stock year-round whether harvesting or husbandry. The shellfish boats operate from various ports across the island and always return to port at the end of a working day, refuelling when required.

Figure 2-8: Shellfish boat LK 88 Aspire [7]

2.1.6 Aquaculture

Approximately one fifth of Scottish farmed salmon is produced in the Shetland Islands, bringing with it local economic and employment benefits. Most of the island's farms are owned by two companies that use a variety of purpose-built ships to carry, feed and harvest salmon as well as service vessels that transport staff and maintain pens.

Stakeholder consultation identified that barges moored to the pens use diesel generators to provide power for lighting and feed distributors. A strategy is being formulated to directly electrify this energy use by connecting barges to the island grid as the pens are typically partially sheltered by land.

Insufficient data has been accumulated from the stakeholders to fully quantify the demand of the sector.

Figure 2-9: NabCat 1499/100 MD aquaculture service boat [8]

2.2 Multi-criteria analysis to suggest decarbonisation options

As part of this project, a multi-criteria analysis was carried out to compare the strengths and weaknesses of various zero and low carbon fuels. The fuels under consideration are detailed below:

Green Hydrogen	Green hydrogen is produced using electrolysers powered by renewable electricity - in the case of Shetland, the wind farms. The production process is energy intensive. Storage of hydrogen can be challenging due to its low volumetric energy density: it can be stored as a compressed gas in high pressure tanks or as a liquid at around -253°C. For the MCA, it is assumed that compressed hydrogen is used, though liquid hydrogen could potentially be used for mainland ferries. Hydrogen can be used in fuel cells or modified internal combustion engines.
Green Ammonia	Green ammonia is produced by combining green hydrogen with nitrogen separated from air using the Haber-Bosch process. It is stored as compressed gas at 10 bar or as a liquid at -34ºC. It can be used in modified internal combustion engines or in some fuel cells. Ammonia is more volumetrically energy dense than hydrogen.
Green Methanol	Green hydrogen can be combined with carbon dioxide to produce methanol, which has a higher volumetric energy density than ammonia. Green methanol is a liquid at ambient conditions and requires minimal adaptation for vessels designed for fossil fuels. To be considered zero carbon, the carbon dioxide must be captured directly from air, seawater, biogas upgrading or biofuel power generation.
Blue Hydrogen	Hydrogen can be produced from fossil fuels, which include carbon dioxide as a by-product. If the carbon dioxide is captured and stored, the hydrogen can be considered blue.
Blue Ammonia	If ammonia is created using blue hydrogen, it is considered blue ammonia.
Waste-derived Biomethane	Biogas can be readily produced from a variety of sources, such as biodigesters, landfill gas recovery and wastewater treatment. On the Shetland islands, an additional potential biomass source may be kelp. The biogas can then be upgraded to remove the CO_2 which could have onward uses (such as methanol) but is often vented to atmosphere.
Waste-derived Bio-alcohols	Bio-alcohols have typically been manufactured by the energy-intensive fermentation of food crops. Second generation bio-alcohols are made from (bio)chemical conversion of lignocellulosic biomass feedstocks, including energy crops, cellulosic residues, and, particularly, wastes. There is limited availability of these feedstocks on Shetland. However, kelp is also a potential feedstock for bio-alcohols.
Waste-derived Biodiesel	Diesel-like fuels are manufactured either by transesterification or hydrotreating of oil containing feedstocks. On Shetland, fish waste has been identified as a potential feedstock. Local green hydrogen could be used for hydrotreating
Batteries	Renewable electricity can be used to charge batteries for use in vessels. Battery-electric vessels have a very high powertrain efficiency and low levels of noise and vibration. However, the energy storage density of existing battery technologies is low compared to other fuels, meaning they are currently only suitable for smaller vessels travelling short distances, or with good availability of recharging facilities.

Table 1: Fuels and energy vectors under consideration

The multi-criteria analysis was carried out at a high level to inform the requirements for hydrogen and the other various fuels. LNG was ruled out of the study due being incompatible with Scotland's long term decarbonisation targets. It was also ruled out as a transition fuel due to the short-term, cost ineffective utilisation of associated infrastructure and not aligning with Scotland's ambition of developing local low-carbon energy markets. The scoring was performed using a combination of public and stakeholder data, as well as Ricardo experience and discussions with other Neptune team members.

The tables below include the scoring for each criterion and their weighting for each fuel, and lays out the numerical results.

	Volumetric energy density of stored fuel							Compatibility of fuel to existing bunkering infrastructure	Current state of vessel/ powertrain technologies	Well-to-tank energy efficiency	Availability of local resources for fuel production	Environmental accidental release risk	Handling risk: NFPA704	Climate change: Zero carbon	Levelised Cost 2030 prices £/GJ prop	Time taken to refuel
	Mainland ferries	Inter-island ferries	Offshore and Services	Fishing offshore	Tugs	Small fishing	Aquaculture etc									
Green Hydrogen	3	3	0	0	3	4	3	2	2	2	4	4	1	4	2	3
Green Ammonia	4	0	0	3	0	0	0	2	1	2	4	2	2	3	2	3
Green Methanol	4	0	4	3	4	4	4	4	3	1	3	3	3	3	1	4
Blue Hydrogen	3	3	0	0	3	4	3	2	2	3	3	4	1	2	3	3
Blue Ammonia	4	0	0	3	0	0	0	2	1	2	3	2	2	1	3	3
Waste-derived Biomethane	4	3	4	3	3	3	3	3	4	3	0	3	2	2	3	3
Waste-derived Bio-alcohols	4	4	4	3	4	4	3	4	3	3	0	3	3	3	2	4
Waste-derived Biodiesel	4	4	4	4	4	4	4	4	4	3	0	1	3	3	2	4
Batteries	0	3	0	0	0	4	0	3	3	4	4	4	4	4	4	1

Table 2: MCA Criteria scoring

	Mainland ferries	Inter-island ferries	Offshore and Services	Fishing offshore	Tugs	Small fishing	Aquaculture
Volumetric energy density of stored fuel	0.6	0.6	0.6	1	0.8	0.6	0.4
Compatibility of fuel to existing bunkering infrastructure	0.3	0.5	0.3	0.5	0.5	1	1
Current state of vessel /powertrain technologies	0.5	0.5	0.6	0.6	0.5	1	1
Well-to-tank energy efficiency	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Environmental accidental release risk	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Handling risk: NFPA704	0.2	0.5	0.5	0.8	0.5	1	1
Climate change: Zero carbon	1	1	1	1	1	1	1
Levelised Cost £/GJ prop	1	1	0.5	0.8	0.5	0.8	0.8
Availability of local resources for fuel production	1	1	1	1	1	1	1
Time taken to refuel	1	1	0.3	0.5	0.5	0.5	0.2

Table 3: MCA weighting factors

The scoring factors were multiplied by the weighting factors, with some critical scores also acting as go/no go points to create the results shown in Table 4. Higher score equals a better result.

Results	People & Vehicle Carriers		Offshore and Services	Fishing offshore	Small boats		
	Mainland ferries	Inter-island ferries			Tugs	Small fishing	Aquaculture etc
MGO	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Green Hydrogen	20.0	20.7	0.0	0.0	18.8	20.9	19.8
Green Ammonia	19.1	0.0	0.0	19.5	0.0	0.0	0.0
Green Methanol	18.5	0.0	17.2	19.8	18.5	21.0	21.0
Blue Hydrogen	19.5	20.2	0.0	0.0	17.8	20.2	19.1
Blue Ammonia	17.1	0.0	0.0	17.3	0.0	0.0	0.0
Waste-derived Biomethane	18.5	19.1	16.5	19.2	16.7	20.0	20.0
Waste-derived Bio-alcohols	19.5	21.2	17.7	20.6	19.0	21.8	21.4
Waste-derived Biodiesel	19.8	21.5	18.1	22.0	19.3	22.6	22.6
Batteries	0.0	26.2	0.0	0.0	0.0	29.0	0.0

Table 4: MCA results

The results were then ranked based on the scores to create Table 5, below.

Ranking outcome	People & Vehicle Carriers		Offshore and Services	Fishing offshore	Small boats		
	Mainland ferries	Inter-island ferries			Tugs	Small fishing	Aquaculture etc
Green Hydrogen	1	4	N/A	N/A	3	5	5
Green Ammonia	5	N/A	N/A	4	N/A	N/A	N/A
Green Methanol	6	N/A	3	3	4	4	3
Blue Hydrogen	3	5	N/A	N/A	5	6	6
Blue Ammonia	8	N/A	N/A	6	N/A	N/A	N/A
Waste-derived Biomethane	6	6	4	5	6	7	4
Waste-derived Bio-alcohols	3	3	2	2	2	3	2
Waste-derived Biodiesel	2	2	1	1	1	2	1
Batteries	N/A	1	N/A	N/A	N/A	1	N/A

Table 5: MCA ranking outcome

In general, the results show that:

- Where possible due to range, batteries have the highest ranking. This is to be expected, as they are the most efficient use of energy.
- Biodiesel and bio-alcohols are generally the next ranked solution, as they are easily compatible with existing vessel and infrastructure. However, there is limited availability for biofuel feedstock in the Shetland islands, and they are likely be in greater demand in other hard to abate sectors such as aviation. Furthermore, biofuels do not align with Scotland's ambition of developing their domestic hydrogen economy and the Shetland islands as a regional hydrogen hub. However, for the vessels that are hardest to decarbonise, biofuels may be one of the only decarbonisation solutions. They could also present a good dual-fuel solution in cases where demand can generally be met by, for example, hydrogen, but there are infrequent cases where a larger energy demand must be met (for example tugs occasionally needed far out to sea).
- Green methanol has similar scores to and is similar in many ways to the biofuels in that it would integrate relatively easily with existing vessels and infrastructure but is reliant on a local source of carbon for conversion of the green hydrogen. Most studies show green methanol having a high production cost.
- Hydrogen generally ranks ahead of ammonia, due to the safety challenges around ammonia on vessels, especially smaller vessels with less well-trained crews, and only ranks ahead of hydrogen in the case where hydrogen cannot provide sufficient range.

Based on the above information decarbonisation options were determined.

Mainland ferries

Of the mainland ferries, the RORO ferries are undergoing procurement as LNG vessels that can be adapted to run on ammonia fuel. Depending on the development of the ammonia safety case, it may alternatively be appropriate to fuel these vessels with hydrogen as it becomes available at suitable scale. The ROPAX vessels are due to be replaced in 2030-2035 and are expected to be hydrogen-fuelled.

Interisland ferries

Inter-island ferries are generally suited for battery-electrification. Depending on the route, the inter-island ferries may require a combination of "opportunity" fast charging at suitable ports and overnight slow charging. Where battery vessels need to make longer trips, for example to dry dock on the mainland, it is envisaged that the batteries could be supplemented by a temporary containerised generator carried on-deck. However, battery electrification may not be possible for all ferries due to range or lack of recharging opportunities during the working day. In which case, hydrogen will generally be the preferred fuel, due to the relatively high fuel volume used precluding use of biofuels.

Offshore service vessels

Offshore service vessels are often European registered and split refuelling between Lerwick, Aberdeen and Kirkwall as suitable for their situation. These vessels vary significantly and are highly challenging to decarbonise, as they tend to be at sea for long periods, have limited space and have sleeping quarters, which generally rules out batteries, hydrogen and ammonia. These vessels are expected in many cases to use biofuels or e-methanol as the pressure grows to decarbonise. It is possible that, in the future, when “shore power” is extended to the oil and gas fields or when servicing windfarms, that these vessels will be able to use shore power when on-station. This could potentially create an opportunity for use of hydrogen fuel to reach the offshore station. However, this is low certainty and is not factored into the hydrogen demand calculations.

Tugs

Tugs are an interesting use-case, as their total energy demand is not large, and on many days, their routine would be suitable for battery-electrification or hydrogen. However, the tugs have to occasionally either travel long distance to support ships at sea, or remain on-station pushing up ships in high winds, both of which will require more energy than can be stored by hydrogen or batteries in the small tugs. Therefore, a suitable powertrain choice could be dual-fuel hydrogen/biodiesel.

Fishing fleet

Pelagic fishing vessels tend to have large, powerful engines, may travel large distances to fishing grounds and spend many days at sea. Not only that, but space is limited both above and below deck, leading to a challenging case for future marine fuels, which are lower energy density than current fossil fuel. We anticipate that unless biofuels are available cheaply and at large scale, future pelagic fishing vessels will use ammonia, which may necessitate a modest increase in newbuild vessel size to accommodate ammonia storage.

Whitefish vessels aren’t time restricted in when they can catch fish, have shorter journeys, and have quotas on how much they can catch. Therefore, it is assumed that they have more available space and are able to refuel with compressed hydrogen. As with pelagic trawlers, a modest increase in newbuild vessel size may be necessary.

Battery electrification, where available is the leading solution for the smaller fishing boats. As local fishing does not take place overnight, there is ample time for recharging at low power, leading to less infrastructure cost than widespread fast charging.

Aquaculture

Aquaculture vessels vary widely, some of which have similar energy requirements to small fishing boats and could use battery-electric, while others have high energy use and limited space, and tethered aquaculture vessels could be practically powered by shore-power. This means there is no “one size fits all” solution for this category.

2.3 Decarbonisation timeline

Ships typically have a lifetime of 30 years so, for most vessel categories, the assumption made in this study is that ships will transition to zero carbon fuels 30 years after their construction date. For the vessel types under consideration, retrofit to zero-carbon fuels are highly unlikely to be economically viable due to space constraints or costly onboard infrastructure changes. For recently built ships It has been assumed that regulatory pressure will drive them to decarbonise by 2045 at the latest, in line with Scotland’s 2045 net zero target. There are a few exemptions to when better data has been provided:

- Shetland Islands Council have a vessel replacement plan in place with approximate replacement dates for each inter-island ferry. These dates have been used instead of the 30-year lifetime assumption. The exception is MV Good Shepherd which is due to be replaced imminently. It has been assumed that a replacement MGO fuelled vessel has been obtained to provide the Fair Isle ferry service until post 2030.
- The mainland RORO ferries are undergoing replacement imminently. Calmac Ferries Ltd have decided that the ferries will be replaced with an LNG propulsion system as an intermediary option with

design capability to be retrofitted to ammonia. The question of when to transition to ammonia has yet to be decided. It has been estimated that regulatory pressure and the availability of an ammonia supply chain will allow this transition to occur post-2035.

- Newly constructed pelagic trawlers hold their value well. Trawler owners take advantage by selling their vessels after approximately seven years for more modern, technologically advanced vessels. This makes this vessel category particularly flexible in when it transitions.

A report by Energy Transitions Commission concludes that at a carbon price of £108/tCO2eq[1] low-cost hydrogen will become the cost competitive solution [9]. The European Union's (EU) Emissions Trading Scheme (ETS) is expected to reach a price £76/tCO2eq by 2030, though at time of writing, the ETS price is already ~€80/tCO_2eq. The UK ETS is expected to be on par, if not more ambitious than the EU ETS. Therefore, it is a reasonable assumption that, in combination with the Shetland Island's excellent wind resource, that past 2035 the hydrogen industry will be mature enough to be low cost and the carbon price will break the £108/tCO2eq threshold as pressures to decarbonise increase. This drives the assumption that the mainland RORO ferry and pelagic trawlers will transition around this time.

Based on these assumptions, a decarbonisation timeline for each vessel category has been generated to show the amount of fossil fuel energy that is displaced with zero carbon fuel energy.

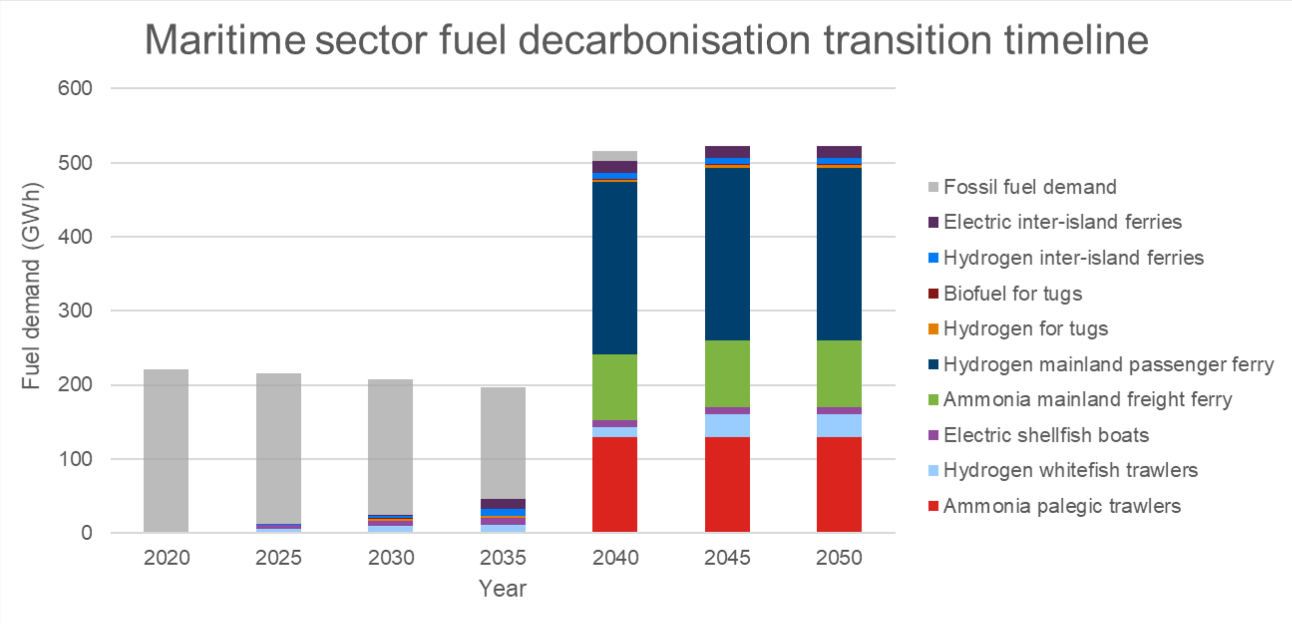


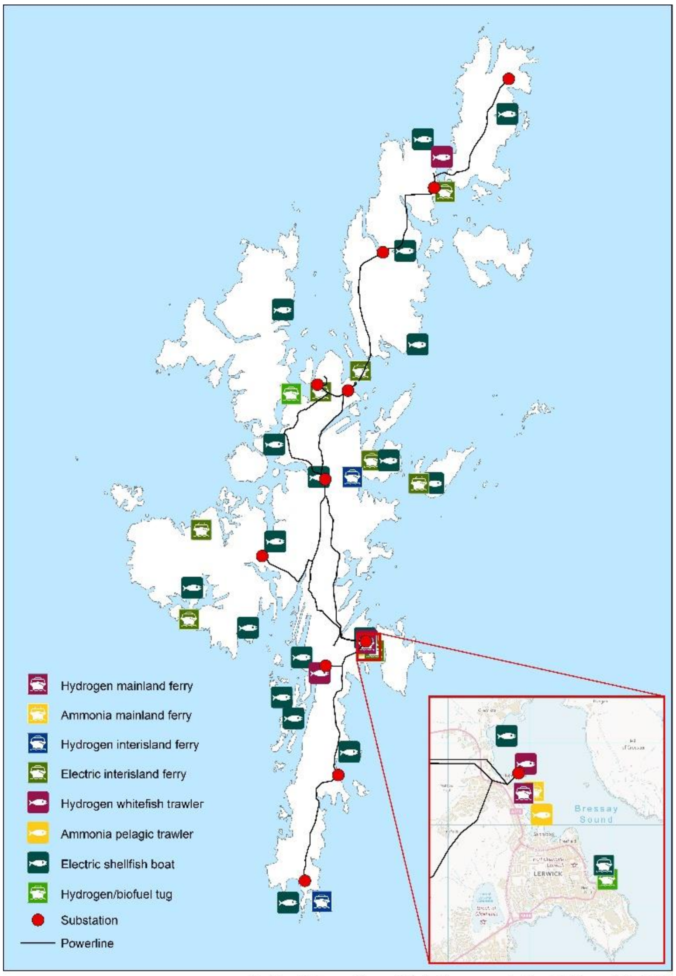
Figure 2-10: Shetland Islands marine fuel decarbonisation roadmap

The graph shows the growth of decarbonised fuels in 5-year intervals and shows the significance individual vessel categories have on demand. Electric and hydrogen vessels are the first fuels to be implemented in the between 2025 and 2030, decarbonising 12% of the total fuel demand. From 2020 to 2035 the transition of vessels to electrification decreases the overall fuel demand. 2035 to 2040 sees a significant step change in overall fuel demand as the mainland ferries are modelled to switch from refuelling LNG in Aberdeen to refuelling hydrogen and ammonia from the Shetland Islands as pelagic trawlers and mainland ferries transition due to the regulatory pressures previously identified. Between 2040-2045 the remainder of fossil fuels are removed from the energy mix as regulatory drivers enforcing Scotland's 2045 net zero target.

2.4 Portside demand

The locations of fuelling needs and the quantity required were determined. The locations are of current demand are plotted on to a map as shown below:

[1] Converted from $145 at an exchange rate of 1.34



Contains Ordnance Survey Data (c) Crown copyright and database right (2022)

Figure 2-11: Refuelling locations for each vessel category

The largest demand centre is in Lerwick where most vessel categories have a presence, and the largest vessels operate from. It is also the only location on the island with an ammonia demand, refuelling pelagic trawlers and the Scottish mainland freight ferry. Hydrogen is also required in Lerwick to refuel whitefish trawlers and the Scottish mainland passenger ferry. As well as electric power, that is required to charge the small fishing boats in Lerwick marina and the interisland ferry to Bressay.

Hydrogen demand is more spread across the various ports where longer-distance interisland ferries and whitefish trawlers operate from. Trucks refuelling small, relatively simple, hydrogen stations will be required to reach these locations cost effectively.

Electric shellfish and inshore boats operate from their home marinas and are widely dispersed across the island. Each marina will require grid infrastructure adequate to provide overnight charging to these vessels. Electric infrastructure will also refuel some interisland ferries. The demand centres of Toft and Gutcher will require significant grid infrastructure to rapidly charge ferries that have a frequent departure timetable and therefore short timeframes to recharge.

The aquaculture fleet has a variety of refuelling centres but stakeholder consultation revealed that these locations will fuel multiple service boats at once. Discussions also lead to determine that direct electrification of tethered barges is a promising solution and therefore, once mapped, would include further electricity demand centres. These demands that are likely to be greater and require more significant grid infrastructure than shellfish marinas due to larger vessel sizes and frequent usage.

2.5 Monthly variation of demand

Of all the vessels, pelagic fishing trawlers are the only category that has a significant seasonality to their operation. They catch migratory fish that pass close to the Shetland islands at certain times of the year. All seven trawlers fish herring in September and mackerel in January. Most vessels also fish mackerel in October with some continuing into the start of November. Lastly, two of the vessels fish for blue whiting in March and April.

The production process of creating ammonia is a chemical process that works most effectively when run continuously, rather than ramped up and down. Therefore storage will have to be sized to store ammonia during months of low demand to build up reserves ahead of months with high demand.

3 Renewable power supply

3.1 Resource characterisation

In order to explore the possibility to decarbonise the maritime industry in the Shetland Islands with efuels, it is important to understand the resources that are available, the existing capacity and the uses that could be given to them. This section, therefore, looks at the energy resources available in and around the Shetland Islands. The overall renewable resource is described, along with existing capacity, to offer a high-level understanding of the energy landscape in the region.

Existing and future renewable energy projects are also described and quantified, in order to offer a view into the renewable resource that is available and could be leveraged on for pushing the decarbonisation of the local maritime sector and beyond.

3.1.1 Wind

Mean wind speeds across the islands are very high and can reach up to 13 m/s, yielding very high potential for wind installations. Mean wind speeds of approximately 11m/s can be found both onshore and offshore. Existing onshore wind installations have recorded annual average load factors of up to 52%, which demonstrates the strong resource present in the area. Larger offshore installations, although more expensive, would be expected to reach even higher load factors than those currently registered for onshore wind. Considering the space available both on land and offshore, a significant amount of wind generation capacity can still be deployed.

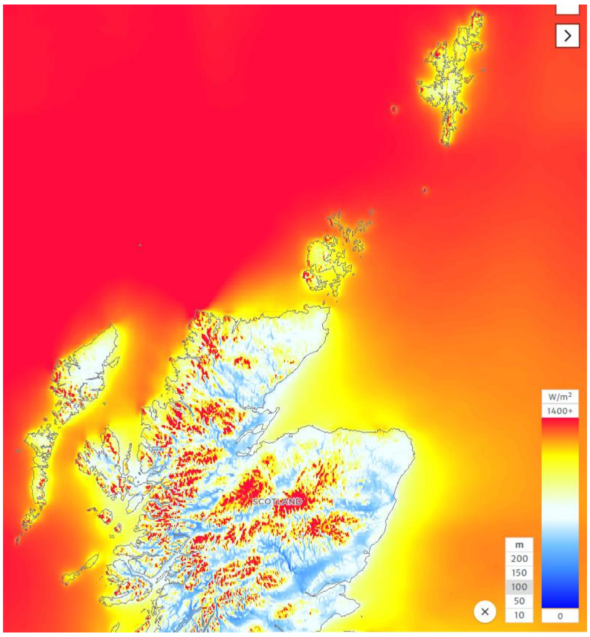


Figure 3-1: Wind resource in Shetland [10]

3.1.2 Tidal

There is significant tidal resource in and around the Shetland Islands. Existing projects have focused on the tidal stream energy that can be harnessed thanks to the existence of multiple channels in the perimeters of the islands and the tide differences experienced across the islands' regions. Although the scale is uncertain, there is considerable potential for further development of this type of energy beyond the existing turbines in Bluemull Sound which have already been producing power .

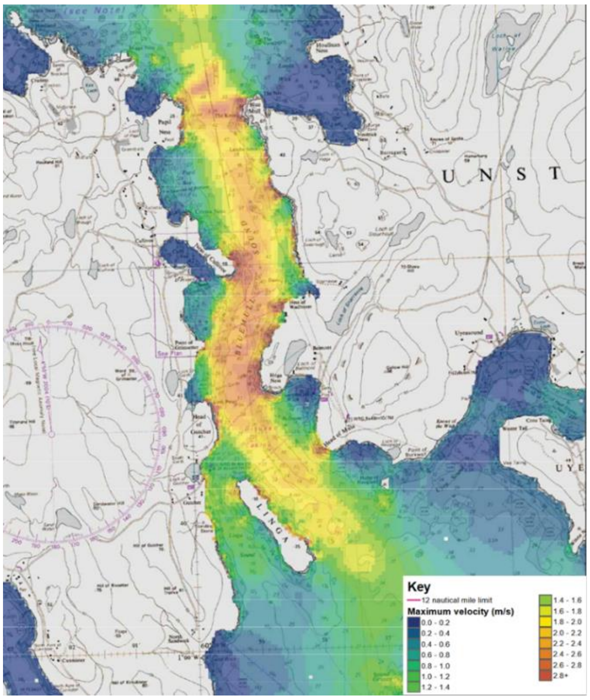


Figure 3-2: Maximum tidal stream velocities in Bluemull Sound, Shetland Islands [11]

3.1.3 Solar

Solar potential around the Shetland Islands is considerably low. A solar PV system in the Shetland Islands is expected to generate around 30% less energy than an equivalent one in the west of England [12]. This considerably limits the potential for solar PV installations, as their output and overall financial benefit would be relatively low output.

3.1.4 Geothermal

While there is no existing geothermal capacity in the Shetland Islands, potential still exists. High temperatures have been detected in the area through previous studies, but exploitable potential has appeared to be limited [13]. Future developments, if feasible, are likely to be used as an input for the local heat network or for power production, rather than marine fuels.

3.1.5 Bioresources and waste

Traditional biomass resources (such as crops or forestry) are available at limited scale in some regions of the Shetland Islands and are used for small scale residential and commercial heat installations [14]. There are, however, other bioresources available that can be harnessed for large scale heat and/or power generation. Due to the presence of fish farms and related industrial facilities, for example, there is fish waste available, which is currently used for heat generation but could be used in the future for power generation as well [15]. Ongoing studies and consultation processes could lead to further use of waste from fisheries for advanced biofuels, although this is currently uncertain.

Additional waste is also available from residential, commercial and industrial activities on both the Shetland and Orkney islands, from where combustible waste is currently being imported and used for heat generation. However, waste volumes imported from Orkney could be reduced in the near future, as the construction of an Energy-from-Waste plant in the Orkney Islands is under consideration [16].

3.2 Existing capacity

The Shetland Islands have multiple existing onshore wind farms, although most of the supply comes from existing fossil fuelled generation. There is also an energy-from-waste plant and important existing infrastructure that could be leveraged on to enable the energy transition. This section explores the existing power and heat generation installations and energy infrastructure currently present in the Shetland Islands.

3.2.1 Onshore Wind

- The 3.68MW **Burradale Wind Farm**, installed in the north of Yell, is comprised of five turbines. The plant has shown the great wind energy potential present in the region, with its turbines reaching an annual average capacity factor of 52% [17]. Most of this capacity was installed between the years 2000 and 2003, so could be facing decommissioning or repowering within the next 5 or 10 years.
- **North Yell Wind Farm (Garth):** This wind farm, owned by the Garth community, is comprised of five 900kW turbines, adding up to 4.5MW of capacity [18].
- **Luggie's Knowe:** Completed in 2015, this single-turbine installation north of Lerwick has an installed capacity of 3MW and is currently the largest turbine in the Shetland Islands [19]. While no information on the load factor of the plant could be found, the plant is expected to yield capacity factors similar to the Burradale Wind Farm, or possibly higher due to the increased height and size of its turbine.

3.2.2 Thermal capacity

- **Lerwick Power Station:** This diesel-fired power plant has served as the main source of energy for the island for several decades. It has an installed capacity of 72.8MW comprised of multiple turbines and engines. The plant also features an 8MW battery, which allows for better integration of the wind resource that has been more recently deployed in the Shetland islands. It is estimated that this plant provides around 50% of the yearly energy needs of the islands [20]. The plant was set to be decommissioned in 2021, yet this has now been delayed until 2025 [21].
- **Sullom Voe Terminal Power Station:** This gas-fired CHP station is estimated to provide ~30% of the Shetland Island's yearly energy needs and primarily supplies the operations of the Sullom Voe gas terminal [20]. The plant has an installed capacity of 20MW and also provides 120 tonnes/hour of steam [22].

3.2.3 Tidal energy

There is an existing tidal stream array at Bluemull Sound in the Shetland Islands: the Shetland Tidal Array, which is the world's first offshore tidal array and started operations in 2016. It consists of three 100kW turbines and is currently being expanded to accommodate three more, which would bring the total installed capacity to 600kW before the end of 2022 [23]. Recent operational reports state that existing turbines are achieving load factors consistently higher than 20%, and that the new turbines to be installed, due to design improvements, would achieve capacity factors higher than 30% [24].

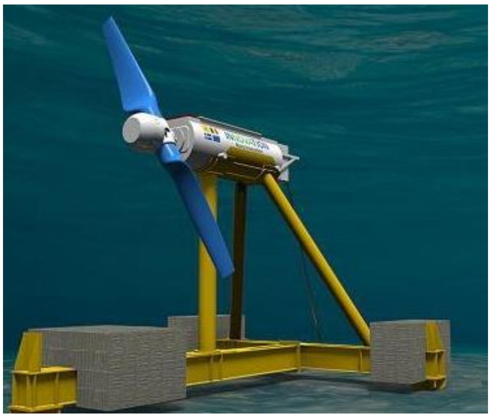


Figure 3-3: Model of Nova's tidal stream turbines used in Shetland [25]

3.2.4 Energy from waste

There is an existing heat plant in Lerwick, operated by Shetland Islands Council, which produces steam for the islands' heat network. Shetland's Energy Recovery Plant currently collects roughly 23,000 tonnes and, through incineration, produces 6MWh of heat per year [15]. Part of the of the incinerated waste at the Energy Recovery Plant comes from salmon fisheries, which provide biomass to help power the facilities.

Figure 3-4: Lerwick energy recovery plant [28]

3.3 Generation buildout timeline

A number of power generation projects are either planned or envisioned for the Shetland Islands. While a considerable volume of capacity has been confirmed, or at least has secured approval for their planning application, significant potential for further developments still exists.

3.3.1 Wind

The high wind speeds present in and around the Shetland Islands is expected to attract substantial interest for the development of both onshore and offshore wind farms. Beyond the existing capacity, multiple projects of considerable capacity have already been announced.

3.3.1.1 Future onshore wind

Several projects have shown intention to develop additional onshore wind capacity in the Shetland islands:

- **Viking wind farm:** This onshore wind project is being developed through a Joint Venture between SSE Renewables and the Shetland Community and is expected to come online in 2024. The wind farm is currently under construction and would consist of 103 turbines, with a rated capacity of 443MW [29].
- **Mossy Hill:** This project, being developed by Peel Energy, is expected to have 12 turbines, adding up to 50MW of total capacity. While the planning application for the project has been approved by Shetland Islands Council, the developer is currently considering development options and possible outcomes of CfD rounds before taking the project forward. [30]
- **Beaw Field:** This project, which has received **approval for its** planning application, would consist of 17 turbines with an aggregated capacity of 72MW [26]. Like Mossy Hill, the possible outcome of future CfD rounds is being considered before moving the project past its current stage [31].
- **Energy Isles:** This 126MW project being driven by a consortium of over fifty organisations, including Statkraft, would be comprised of 29 turbines and sited north of Yell. At the time of writing of this report, the project's planning application has not yet been approved [32]**.**

These projects could add up to approximately 690MW of onshore wind capacity and achieve capacity factors similar to the ones observed for the existing Burradale Wind Farm, which would represent a significant addition to the island's renewable energy output. More projects, however, could also be developed and are likely to do so, considering the strong wind resource and the potential sources of demand for power: from the electrification of oil and gas operations and local demand to the potential production of hydrogen and other electrofuels in the near future.

3.3.1.2 Future offshore wind

Even after considering the offshore wind deployment timeline already described in this section, significant additional potential remains available around Shetland. Despite no successful projects in the Shetland area during the Scotwind leasing round completed in March 2022 it is still likely that offshore wind projects will be completed in future. While it is difficult to estimate how much deployment could occur in the area, it is estimated that projects would have capacities between 300-500MW but could go up to 10GW in size and could come online before 2030 [34].

Projects that have shown intention and progress towards building additional offshore wind capacity around the Shetland islands include:

- **Cerulean Winds:** This £10 billion proposed project would be comprised of 200 floating offshore wind turbines in West of Shetland and in the central North Sea. Project descriptions seem to indicate that the expected commissioning date is 2026. Turbines would be 14-15MW in size, resulting in a total potential installed capacity of 3GW. It remains unclear how much capacity would be deployed at each site, and how much of it would be used to produce green hydrogen, which is also part of the projects' scope.
- **Aker's Northern Horizons project:** Aker has recently unveiled plans to build a 10GW floating wind farm consisting of 500 turbines, each with a 20MW capacity. They expect operation to begin in 2035 and are considering using floating platforms to produce hydrogen close to the wind farm, for later transport to a refinery in Sullom Voe via pipeline [35].

3.3.2 Interconnection

The Shetland islands is currently an islanded electric grid system with no connection to mainland. However, the great renewable resource present in the area offers significant opportunity for the building of an interconnection that allows the exporting of locally produced renewable power. This opportunity is currently being pursued by SSE, who is constructing a 600MW HVDC interconnection between Shetland and mainland Scotland, with most of the 260km of cabling going underwater [36].

According to current plans, it is expected that a 320/132kV substation would be installed in Upper Kergord (on the Shetland side) and an HVDC switching station would be built at Noss Head in Caithness (on the mainland side). The project is expected to come online in 2024. The Viking, Beaw Field and Energy Isles projects, whose aggregated installed capacity adds up to approximately 650MW, have signed connection agreements and are seeking to connect to the Scottish Hydro Energy Transmission Network [26].

The Maali Link, which is another interconnection being considered (although not confirmed), could add 600MW of interconnection capacity between Norway and Shetland. This could increase energy security for Shetland while also potentially enabling the exporting of wind energy from both Shetland and mainland Scotland (should the Caithness-Kergord interconnector be operational). Even combined, these interconnects will be unable to transmit the majority of the power from Cerulean Winds or Northern Horizons, meaning conversion to hydrogen is the likely option for the energy from these wind farms.

3.3.3 Generation capacity timeline

While the renewable installed capacity and generation in the Shetland Islands remain relatively low, they are expected to increase considerably over coming years. Should projects in planning and scoping stages materialise, there could be an increase of over 3.6GW of renewable installed capacity between now and 2030, and of over 10GW more by 2050 as shown in the figure below.

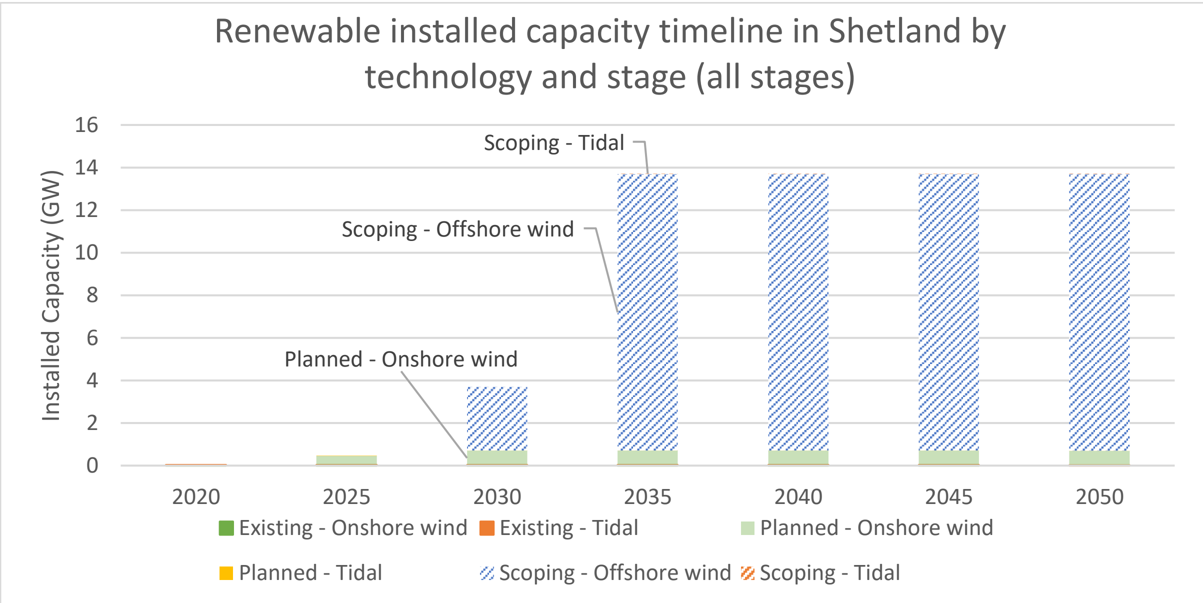


Figure 3-5 – Renewable installed capacity timeline in Shetland by technology and stage

3.3.4 Balance and grid considerations

Renewable power potential in the Shetland region is significant and would comfortably suffice to both supply local energy needs and meet increases in demand from the electrification of oil and gas operations as well as the production of efuels. However, as has been described, there is no current interconnection to mainland that could serve to export renewable power if there was a surplus. Announced projects (although unconfirmed), would by far exceed the capacity of the Shetland Link.

From a planning perspective, it is therefore important to consider the need for alternate routes to market for future renewable power projects, since export capacity would be limited. In this sense, green hydrogen provides a solution, as renewable power could be used to run electrolysers directly, without the need to inject significant amounts of power to the local grid or export it through interconnectors. Both the Cerulean Winds and Northern Horizons projects are envisioning the production of green hydrogen directly from their offshore wind generation, which would considerably reduce the stress on the interconnection network.

3.4 Conclusions on supply

- While there are multiple renewable energy installations in the Shetland islands, their output is currently insufficient for supplying local electricity demand or future increases with renewable power.
- There is, however, considerable potential for further renewable energy deployment in the Shetland Islands, for a variety of resources: from tidal stream to geothermal but mainly for onshore and offshore wind.
- The current absence of interconnections to mainland limits the islands' potential to export power, acting as a barrier for exploiting the considerable renewable resource of the region.
  - The Shetland Link interconnector project, which would install 600MW of interconnector capacity, could serve as a means for exporting renewable power to the UK market.
- There are multiple generation projects expected along the timeline that could dramatically increase the renewable capacity installed in the region.
  - Some of these projects are looking to produce green hydrogen, which could serve as an alternative to exporting renewable power through the upcoming interconnector, whose capacity is likely to be exceeded by the installed capacity of projects currently in the planning and scoping stages.
  - Although highly uncertain, announced projects could, in the future, fuel the production of over 1 million tonnes of green hydrogen per year.
- Blue hydrogen could also be produced on the island, given the strong presence of gas resource, capacities and infrastructure that could be leveraged on for both the production and transport of the gas and the storage of CO_2.

4 Supply and demand timeline comparison

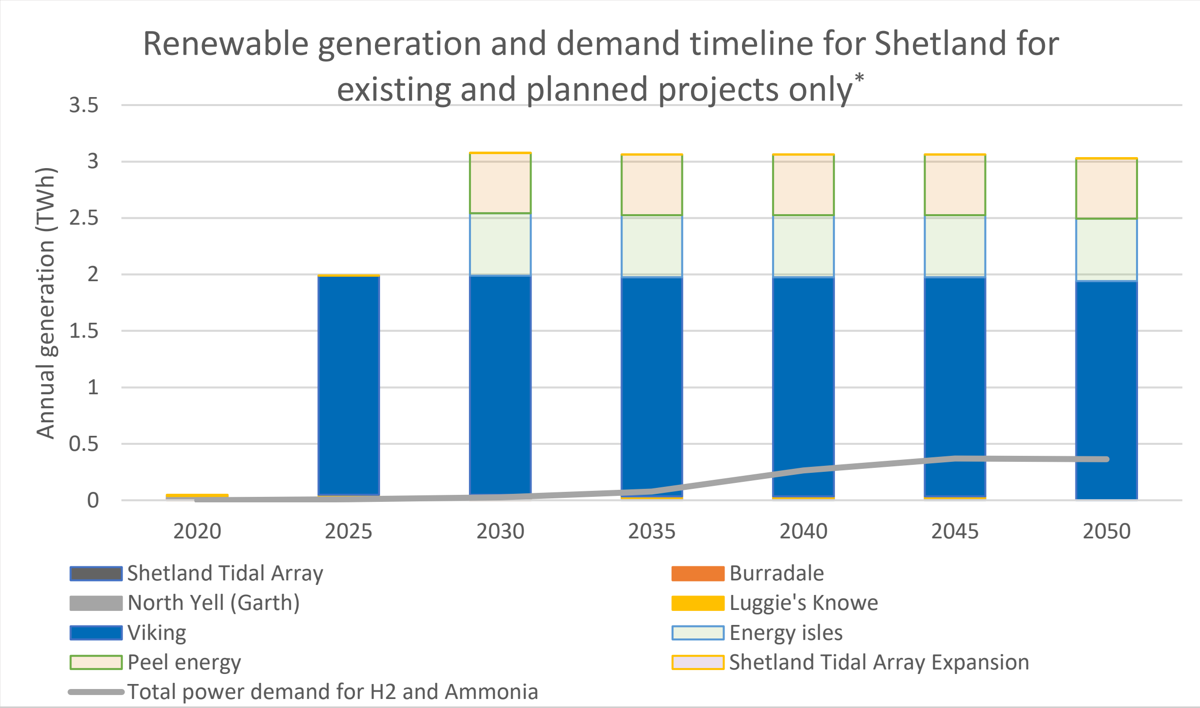


Figure 4-1: Renewable generation and demand timeline for Shetland by project and stage (GWh). Projects in planning and scoping stage are shown with transparent background and solid borders[2].

Considering the demand and capacity deployment timeline for the Shetland Islands, total renewable generation would be enough to cover local power demand, expected increases from electrification of oil and gas operations and other demand segments, as well as the production of green hydrogen and green ammonia for the local shipping sector and beyond.

In summary, as Figure illustrates, the power required for hydrogen and ammonia production for the decarbonisation of the shipping industry of the Shetland Islands can be provided through renewable generation projects that are either already in place or currently under construction.

5 Infrastructure opportunities

This section is a review of the existing energy infrastructure on the Shetland Islands, assessing how it might be beneficial in supporting a hydrogen economy that can fuel maritime decarbonisation.

5.1 Power grid infrastructure

Power infrastructure is required to supply vessels transitioning to electric and to power electrolysers producing hydrogen. The Shetland islands (with the exception of Foula) are interconnected with a network of 33kV and 11kV circuits. The network is currently electrically isolated from the mainland, however, this is due to change with the construction of the Viking wind farm and an HVDC interconnector to the mainland. A converter station will receive the interconnector in Kergord, close to the Viking wind farm. 132kV lines will be constructed, extending North to Yell to connect to the future Energy Isles wind farm and South to Lerwick where a grid supply point will connect with the existing power network. The interconnector, 33kv and 11kv network infrastructure can be seen in the image below.

[2] *Excludes projects in scoping stage, namely the Northern Horizons and Cerulean Winds projects. Assumptions are made regarding load factors for each technology.

Figure 5-1: Map showing the HVDC interconnector (purple), 33kV lines (green) and 11kV lines (blue) [37]

Three-phase 11kV lines have the theoretical capacity to provide shorepower and charging capabilities to vessels docking at the edges of the grid such as the ferry that departs from Laxo. Overnight charging could avoid network congestion that may occur during the day, however, most of the properties outside of the range of Lerwick's district heat network utilise storage heaters that draw a high load at night. With this added complexity, it is recommended that each port is individually assessed to ensure the existing power infrastructure can accommodate the needs of electric vessels.

Existing infrastructure has enough capacity to charge vessels overnight but must be individually assessed, particularly considering that demand must compete with storage heaters that heat some properties outside of Lerwick.

Commercial electrolysers have large demands that require three-phase electrical connections. The size of the electrolyser will dictate the size of the voltage input required. The table below shows the power supply to the ports identified in the study as needing a supply of hydrogen.

Supply	Lerwick	Sullom Voe	Scalloway	Laxo	Cullivoe	Grutness
132 kV	✓	✓*				
33 kV	✓	✓	✓	✓*	✓*	✓*
11 kV	✓	✓	✓	✓	✓	✓

Table 6: Power supply to ports. (*close to infrastructure that could be extended)*

All sites are located close to 11kV power supplies. Lerwick, Sullom Voe and Scalloway also have 33kV power supplies directly at the port. Laxo, Cullivoe and Grutness have 33kV power supplies within a few kilometres of their ports that could be extended to provide a direct supply. Lerwick is due to have a 132kV grid supply point built close to the port. A 132kV circuit will pass close to Sullom Voe on its route to Yell so a connection could be made to provide a supply.

5.2 Oil and gas infrastructure

The oil and gas sector is one the largest incomes in the Shetlands economy. A transition to a low-carbon economy presents both threats and opportunities to this sector. Thanks to a key combination of drivers (such as strong renewable resource, the presence of both fossil fuel resource and associated infrastructure, and potential sources of demand), existing sector stakeholders and new hydrogen developers have started looking at producing both blue and green hydrogen in the vicinity to supply the local demand and export to the UK mainland and internationally.

5.2.1 Sullom Voe oil terminal

The infrastructure at Sullom Voe is built to facilitate the extraction, transport and export of oil and gas. However, there is opportunity for it, and the skilled staff who operate it, to be adapted for low-carbon hydrogen production. The Sullom Voe oil complex is operated by Enquest on behalf of a consortium of 12 oil companies with site ownership interests. Three pipelines feed the terminal, two from the East of Shetland and one from the West of Shetland, and one pipeline provides export to St Fergus gas terminal on mainland Scotland. Gas separated from the oil is used to power the on-site power station discussed in 3.2.2. Four jetties serve oil transport vessels exporting oil to the Scottish mainland and internationally. As a result of its remote location, the Sullom Voe Terminal has to be entirely self-sufficient, particularly where emergency services are concerned. On site there is a fire brigade and a pollution response team, both of which hold regular exercises to test their readiness to cope with emergencies.

At the time of writing, it is unclear whether oil and gas activities in the region will ramp-down, or whether they will increase, depending on the ongoing discussions around the Cambo oil field Northwest of Shetland.

Figure 5-2: Sullom Voe Oil Terminal, Shetland Islands [27]

As identified by the Orion energy project, much of Sullom Voe's gas infrastructure could be repurposed for hydrogen production whilst still supporting the oil and gas industry. Blue and green hydrogen could be produced for local use as well as exported internationally through existing connections to the UK mainland and Europe. Existing experienced and skilled workers can more easily be retrained to work safely with hydrogen. This transition has the opportunity to benefit the island economically by retaining an energy industry that would otherwise be phased out by decarbonisation ambitions.

5.2.2 Further hydrogen infrastructure interests

The Orion Project envisions the production of green hydrogen powered primarily by offshore wind installations. Additional onshore wind and tidal capacity could also be used to power hydrogen production [34]. No indication has been found yet on the potential electrolyser capacity that could be installed, but project documents state that up to 2GW of offshore wind could be dedicated for hydrogen production processes.

Aker's Northern Horizons project, first discussed in 3.3.1.2, envisages large-scale production of green hydrogen and derivative fuels for worldwide export. Hydrogen is produced on floating offshore production platforms powered by 10GW of floating offshore wind and piped to land to be converted into ammonia, liquid hydrogen and synthetic fuels.

The Cerulean Winds project plans to develop 3GW of floating offshore wind capacity to feed offshore facilities and three electrolysis sites on Shetland, Northeast Scotland, and North England.

The Orion Project is also considering the production of blue hydrogen, using natural gas supply from the Laggan Tormore gas condensate fields [34]. There are multiple synergies that could be harnessed with the existing gas infrastructure. The existing pipelines supply feedstock natural gas directly to Shetland and, once wells are depleted, could be retrofit to transport hydrogen for storage or CO_2 for sequestration. The workforce at Sullom Voe also have skills and experience in working with natural gas.

While no indication has been given on the volume or capacity that could be installed, the combination of drivers could make blue hydrogen an important opportunity for the Shetland Islands' energy industry.

5.2.3 Domestic gas infrastructure

At a residential and commercial level, there is no gas distribution infrastructure present in the Shetland Islands, meaning that households do not receive gas directly from a grid and mostly rely on oil boilers and storage heaters for heating [26]. This disqualifies the potential for retrofitting existing infrastructure to distribute low pressure hydrogen around the island.

6 Lerwick refuelling demand case study

Since Lerwick is the largest fuel demand center, it will be used as a case study. The study reviews production, transport, storage and bunkering of fuels into vessels. A specific design philosophy is applied taking into account:

- existing and future planned island energy resources and infrastructures
- seasonality of refueling per vessel category
- several technical parameters
- health and safety aspects for each fuel
- location of production, storage, bunkering

The following table presents a summary of the vessel categories and their respective characteristics.

Vessel	Fuel	Refuelling Seasonality	Total Annual Demand (tonnes)	Single Refuel (tonnes)	Daily Fuel Production Requirements (tonnes)	Daily Hydrogen Feedstock Required (tonnes)	Refueling buffer method	Refuelling Method
ROPAX	H_2	Daily	7000	25	25	N/A	Pressurised storage at quay	Pressure Balancing
Whitefish Trawlers	H_2	Steady all year (undetermined variability)	580	1.5	1.5	N/A	Pressurised storage at quay	Pressure Balancing
Tugs	H_2	Once a month (due to low energy usage)	90	4	0,013	N/A	Pressurised storage at quay or Tube Trailer delivery	Pressure Balancing
RORO	NH_3	Twice a week (e.g. one trip on Monday and one trip on Thursday).	17200	150	45	7.5	Storage tanks North of Greenhead	Ammonia Discharging Arm Jetty
Pelagic Trawlers	NH_3	90% (Sep-Jan) 10% (Mar-Apr)	25000	420	68	12 (assumed seasonal storage facility)	Storage buffer tanks North of Greenhead	Ammonia Discharging Arm Jetty

The multi-criteria analysis completed in section 2.2 resulted into two main efuels for the case of Shetland Islands, together with battery electrification. These fuels are ammonia and hydrogen. The primary component of both fuels is hydrogen. A notable mention is required to methanol as it has also been identified as a potential transitional fuel, therefore a section in the Appendix is dedicated to methanol. Coming back to hydrogen, it will be produced locally next to the planned switchgear where high voltage equipment will bring most of onshore wind capacities near Lerwick. The total size of the electrolyser facility depends on the maximum daily hydrogen demand that will be needed at the port location. Due to the critical nature of ferries and fishing to the community, a degree of contingency is required for the fuels. The size of the storage infrastructure has been estimated from data provided by stakeholders on refuelling patterns of the different types of vessels that arrive to the port. In particular detail, the maximum daily hydrogen demand at the port is broken into:

- The ROPAX mainland ferries (hydrogen in future) visit Lerwick every day. Thus, their demand is highly predictable. A single refuel of the ROPAX consumes 75m^3 of MGO (762MWh) which translates to 809MWh of hydrogen equivalent fuel (~25 tonnes of H_2). Each ROPAX is docked 45% of time in harbour. It usually stays in Lerwick for ~10-12 hours. It's current refuelling time is approx. 1 hour.
- The whitefish trawlers (hydrogen in future) have more of a consistent monthly refuelling demand. Therefore, it is assumed that refuelling occurs once per week for each of them. There are 14 Whitefish Trawlers in Lerwick which could refuel once per week. All of them are of similar size. Thereby there will be a total of 728 refuellings per year at the port. The total amount of energy required per annum is (18.1GWh MGO = 19.1GWh H_2). Thereby a single refuel will be 26MWh of H_2 (~800kg of H_2). Expressing this in a monthly demand it equates to ~48 tonnes of H_2 but since their refuelling frequency is unknown it is assumed that 1.5 tonnes of H_2 should be produced and buffered per day near the bunkering facilities of whitefish trawlers at the port quay.
- The two Lerwick Port Authority tugs (hydrogen in future) are assumed to have an irregular refuelling frequency, which currently occurs once a month due to their low energy use. Tugs would require monthly a 0.4 tonnes of hydrogen which translates to buffering 0,013 tonnes per day which is negligible with respect to the other hydrogen vessels.
- The RORO mainland freight ferries (ammonia in future) visit the Lerwick port 2 times per week all year round and are assumed to be evenly distributed (e.g. one trip on Monday and one trip on Thursday). It has been estimated that ROROs require ~150 tonnes of ammonia for each refuelling which happens twice a week, thereby 300 tonnes of ammonia per week which on a continuous basis on the HB plant would mean a daily production of ~45 tonnes of ammonia which would require ~7.5 tonnes of hydrogen
- The seven pelagic trawler fishing vessels (ammonia in future) have a seasonal predictability in terms of operation (mostly in January, September and October) but they exhibit an unpredictable daily refuelling. Therefore, seasonal buffering in ammonia spheres is required in order to allow continuous production from the Haber-Bosch plant. The total ammonia demand yearly is 25.000 tonnes. 90% of this demand is seasonal therefore buffering is required in order to minimize production disruption of the Haber-Bosch plant. This means the total annual ammonia demand should be continuously generated to fill up the tanks all year round. Therefore 25000 tonnes of ammonia will require ~4300 tonnes of hydrogen annually which means that daily there should be at least ~12 tonnes of hydrogen as feedstock for ammonia resulting in a daily production of ~68 tonnes of ammonia.

The monthly refuelling energy requirements are summarised in the figure below.

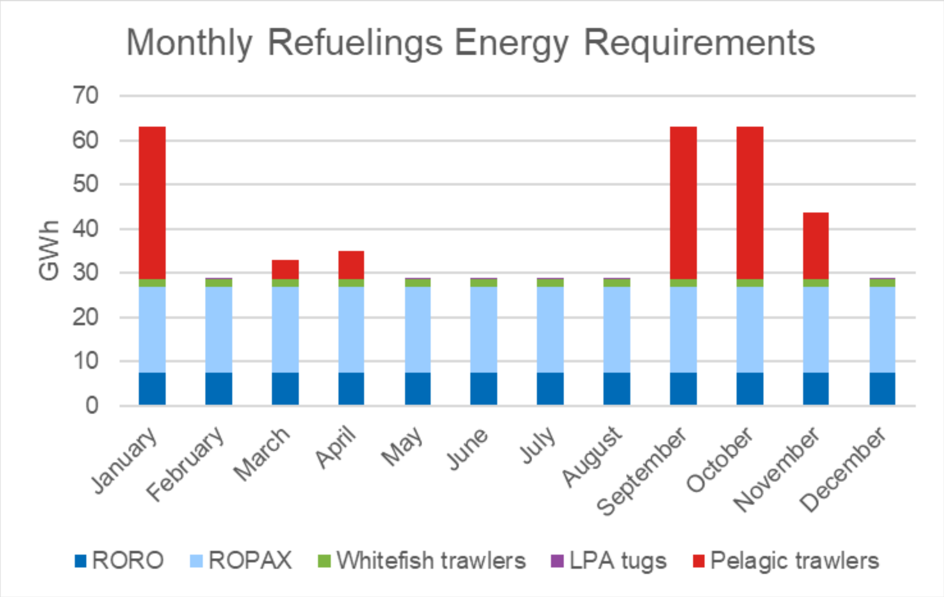
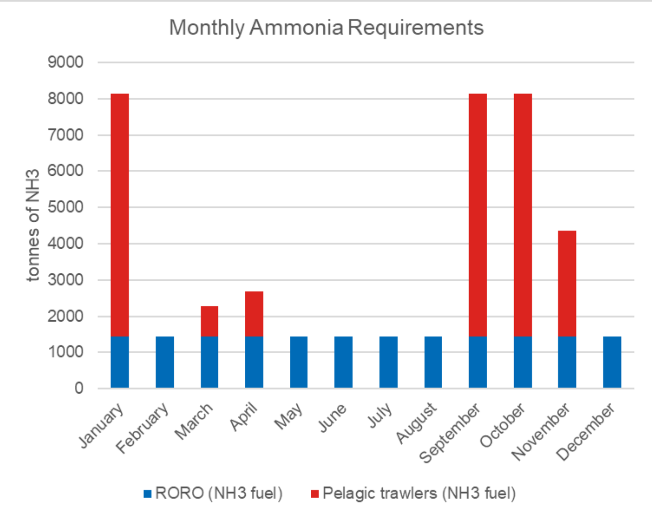


Figure 6-1: Monthly ammonia and hydrogen maritime fuel requirements in Lerwick port

The figure below now breaks the seasonality into the 2 different commodities of ammonia (as a fuel) and of hydrogen (as a fuel and feedstock for ammonia production). The seasonality poses a sizing challenge in between the production plant's capacities and the storage requirements. The optimisation of such sizing is out of the scope of this study. However, a preliminary sizing that could accommodate the maritime sector's demand for these new fuels has been undertaken.



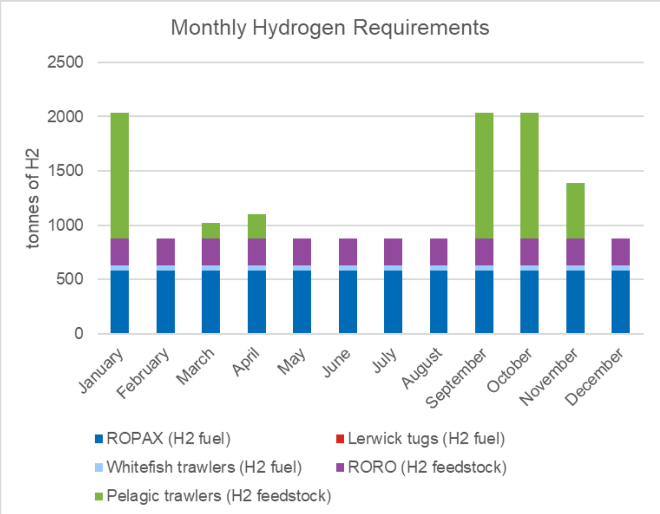


Figure 6-2: Monthly ammonia and hydrogen maritime fuel requirements in Lerwick port

7 Hydrogen production

The Lerwick case study shows that hydrogen is an essential part both as a fuel and as feedstock for ammonia production. About 7,700 tonnes are required annually as fuel and 7,400 tonnes are required as feedstock for ammonia. This totals to ~15,000 tonnes of hydrogen annually. Due to the immense amount of wind potential present in the island and the announced projects together with the electrical grid infrastructure upgrades, it is understood that wind energy will play a fundamental role into hydrogen production. Therefore, hydrogen production technologies that can keep up with potential intra-hourly fluctuations are assumed such as PEM and Alkaline. The location of hydrogen production is also important. The following options are present:

- Hydrogen produced next to a wind farm (e.g. Viking Wind Farm)
- Hydrogen produced in Lerwick
- Hydrogen produced in Sullom Voe (with subsequent export potential of hydrogen)

As some of the concepts have limitations and constraints due to the necessity to transport the produced fuels to the port of Lerwick, the concept of hydrogen production in Lerwick is assumed in this study.

7.1 Daily requirements

The above analysis results into ~50 tonnes of daily hydrogen production requirements both as ammonia feedstock and as hydrogen fuel, but due to contingencies a 20% safety factor is used resulting in ~60 tonnes/d. Assuming an electrolyser with efficiency of 55kWh/kgH_2 (such as PEM), the minimum hourly production requirement of 2,500kgH2 results into an electrolyser plant with a rated capacity of ~140MW. This of course assumes a 100% utilization factor which in reality is not possible as maintenance and other factor will justify increase in production capacity which is shown in Section 7.4 resulting to a plant of 180MW.

7.2 Footprint of production

Several studies estimate various figures for the total area requirements of an electrolyser plant of similar size. In particular, these are summarised in [38] and [39].

- German study estimates an area density of 63 m^2/MW for a 100MW plant
- Siemens estimated 50 m^2/MW for a 300MW plant (180mx80m)
- ITM showed an area density of 35 m^2/MW for a 100MW plant (40mx87m)
- McPhy proposed a plant with area density of 45 m^2/MW for a 100MW facility.

Therefore, assuming a 180MW with the high-end area density of ~65 m^2/MW a plot of 125m by 125m is required. Pipelines will transfer hydrogen to storage and bunkering facilities at the port refuelling locations to refuel whitefish trawlers, ROPAX and tugs. A suitable location of the hydrogen production facility is between the ferry terminal and energy recovery plant near Mossy Hill and close to the announced 132kV substation.

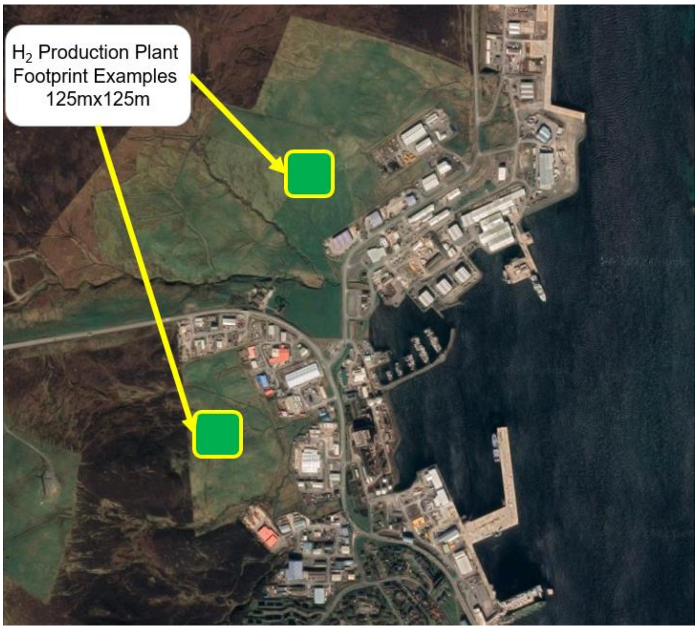


Figure 7-1 options for electrolyser locations

7.3 Grid aspects

This section discusses how the hydrogen production electricity demand might influence Lerwick's electricity sector.

- The hydrogen production plant will be located close to the Mossy Hill, which is where a 132kV substation (labelled grid supply point - GSP - below) will be located to facilitate interconnection of the Shetland's power grid with the Scottish mainland. This HVDC link connection will also serve the large quantities of renewable onshore wind production (initially primarily coming from the 443MW onshore Viking Wind Farm). The electrolysis plant could therefore play a flexibility role for the transmission of power to Scotland.

- Assuming an electrolyser at full load (180MW) and layering the maximum residential, commercial current load for Shetland Islands (48MW) [40] results into a total load of ~230MW. The onshore Viking Wind Farm alone has the potential to cover the total peak load. Several electrification paths have been announced in the ORION Clean Energy Project for Sullom Voe Terminal and Shetland gas plant (30MW), Sullom Voe Port (4MW) and charging of light vehicles (40MW). This could increase the peak electrical demand to ~300MW. Comparing the peak capacities of ~300MW and the Viking Wind Farm 443MW with ~50% capacity factor would mean that additional thermal capacity or grid import might be required at certain periods.

Figure 7-2 Grid supply point, electrolyser and pipework (yellow – hydrogen, red – waste heat to local heat storage)

7.4 Renewable energy supply balance

To analyse the behaviour and impact that the power and hydrogen elements that would make the ecosystem of the Shetland Islands under a decarbonised shipping scenario, an energy model of the islands was made. The software utilised for simulation was HOMER Pro and the scenario was built with supply and demand equal to 2045 projections. This year was chosen as reference since the relatively mature levels of hydrogen and ammonia demand expected by that year would allow valuable insights to be drawn around the behaviour of energy supply, demand and storage across both electricity and hydrogen.

Assumptions

Considering the aim of the energy model, the results of the sizing exercise and software limitations around the simulation of energy systems integrated into a wider grid, the following general assumptions have been considered:

- **Local balance of hydrogen demand and supply:** The model assumes that all hydrogen demand and load is to be served by locally produced hydrogen and that there is no hydrogen export outside of the Shetland Islands. This assumption may change considerably in the future, as a hydrogen export industry is considered feasible and actively being considered by the relevant stakeholders. Changing this assumption would have important implications for the analysis as it would increase hydrogen demand and, therefore, increase the optimal sizing of electrolysers and, therefore, the optimal sizing of both power and storage infrastructure.
- **Aggregated wind capacity:** For simplicity, wind plants were clustered and simulated as a single wind farm in the model. While different plants would have different yields, mostly due to their hub heights, it is not possible to know the planned hub height for sites that have not been commissioned, which comprise the bulk of the generation expected to be online in 2035. Considering the size of the island

and the wind speeds in the area, the difference between offshore and onshore wind speeds is not significant, as was shown in the energy resource characterisation. It is therefore expected that this assumption would not change results considerably.

- **Simplified grid connection:** The model considers a connection to the main grid to represent the Viking Link interconnector. The software used in the analysis focuses on the simulation of islanded systems and has limited capabilities regarding the simulation of grid prices. This connection has been modelled in a simplified manner, in which import, and export rates have been assumed to be flat. A more granular assumption would result in more realistic behaviour of power plants and storage assets, as these would operate in ways that would optimise their financial results based on the behaviour of wholesale, balancing and ancillary services markets.
- **Constant hydrogen demand:** hydrogen demand was assumed to be constant throughout the year. This assumption was taken since the operation of the Haber-Bosch plant would need to be steady and continuous, yet green ammonia demand is expected to have strong seasonality due to the operation of the pelagic trawlers. This means that ammonia would need to be produced at a rate that allows for ammonia storage tanks to be steadily filled throughout the year – which results in the need for a steady supply of hydrogen. This would be added to the hydrogen demand for ships that would utilise it directly which, in order to maximise the utilisation of the electrolysers, would also need to be produced at a relatively steady rate. Overall, as estimated in previous sections, this results in a steady demand of approximately 60 tonnes of hydrogen per day to account for the contingencies.

It is worth bearing in mind, however, that the presence of storage would still allow a certain level of optimisation of equipment sizes and operation. While a more granular approach could offer more insight into the correlation of demand, generation profiles and their interaction with both power and hydrogen storage, there is insufficient information to build an hourly model of hydrogen demand. Furthermore, the private ownership of renewable assets and the inability to model their interaction with the wider wholesale and balancing markets, would limit the accuracy in behaviour of the model. The current approach, however, still allows for the impact on local resources and demand to be assessed and for insights on infrastructure sizing to be drawn.

The model was built considering the different type of power generation that is expected to be present on the island by 2045, as described in Chapter 3 including:

- Thermal generation
- Battery storage
- Onshore wind generation
- Marine energy
- Offshore wind generation
- Mainland interconnection:

It is worth noting that, in the case of offshore wind farms, only those that have acquired planning permissions were considered in the analysis. This criterion was applied since:

- The software used for the analysis simulates an islanded system (i.e., a system that has limited or no interconnection with the main power system in the region). Therefore, including plants that are significantly larger than the local demand will cause disruptions in the results, such as excessive grid export at times of high renewable generation. This, however, would be unrealistic since net export would be limited to 600MW given the capacity of the Shetland Link interconnector.
- These larger plants (i.e., Northern Horizons and Cerulean Winds) have signalled plans to have their own electrofuel production facilities connected directly to their plants, which would significantly change the operation and interaction of supply and demand on the island.
    - Furthermore, the specific array and associated capacity for electrofuel production are not yet known (e.g., electrolysers size, interaction with the grid, renewable capacity dedicated to hydrogen production, etc…), and therefore cannot be modelled properly.
- At the time of publishing of this report, it is considered uncertain whether plants that have not acquired planning permissions will go ahead.

Analysis of results and behaviour

The scenario modelled for the Shetland Islands is characterised by having an energy supply that is much larger than local demand, even when not considering the wind farms that have not acquired planning permissions. The optimal system configuration according to results features a 180MW electrolyser, relatively larger than the

140MW capacity estimated as the minimum necessary in the first sizing exercise. As explored below, this behaviour is attributed to the advantage of using power from renewables (rather than thermal generation or the mainland grid) to produce power and the need to oversize the electrolyser in order to take advantage of renewable output peaks.

The results of the model and simulation clearly indicate that the Shetland Link interconnector will be used mostly for exporting excess wind generation to mainland Scotland. However, it is also shown that, at certain times, the interconnector will be crucial to satisfy local demand. The role of the Shetland Link in balancing local power supply and demand would perhaps be more crucial if instantaneous balancing requirements were also needed. However, the model is simulated with a one-hour granularity and therefore these instantaneous requirements are not visible.

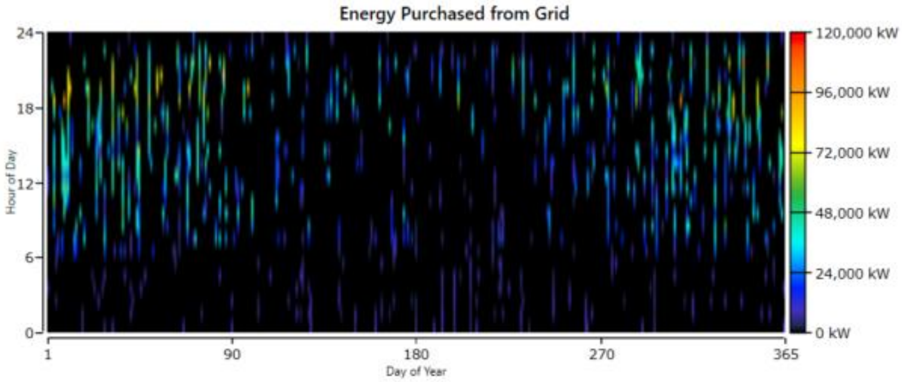


Figure 7-3 - Energy purchased from the mainland grid in 2045 according to model results

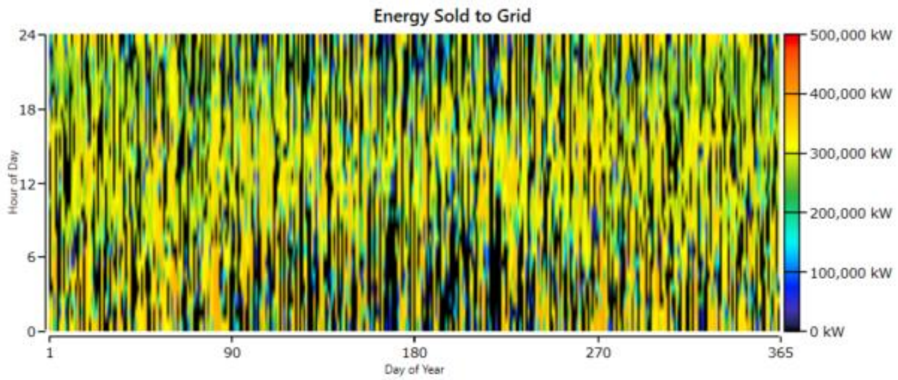


Figure 7-4 - Energy sold to the mainland grid in 2045 according to model results

The interconnection results in lower costs of hydrogen – in a scenario in which the Shetland Interconnector were not present, it would be challenging to optimise the capacity factor of the electrolyser without significantly impacting the cost of the hydrogen produced. Despite the abundance of local wind resource, the high correlation in the output between the different generation sites (given their closeness) results in periods of both excess and lack of renewable output. Without the interconnector, the electrolyser would need to rely on the output of the Sullom Voe plant, which would have considerable associated costs and would result in considerable emissions associated with the production of hydrogen.

If, on the other hand, the electrolyser were to be oversized to capture the peaks of wind generation, the cost of hydrogen would still be impacted as the higher capital costs of the electrolyser would be distributed among the same level of demand as in the first scenario. It is clear then that the Shetland Link serves not only to enable the exploitation of the local wind resource of the Shetland Islands, but also to produce low-carbon hydrogen at a lower cost than under an off-grid scenario.

Local renewable energy balance

By analysing the demand and generation in each of the one-hour steps in the results, it is possible to assess the extent to which local renewable capacity is able to cover the requirement of the Islands, including demand from electrolysis.

Figure 7-5 below shows the resulting renewable energy balance duration curve. It can be observed that, for over 70% of the time, there is a surplus of renewable energy – meaning that both the power requirement of the island and the demand for green hydrogen production are being met with renewable power and a surplus is being exported through the Shetland Link interconnector. This surplus is shown with a green background. Another interesting behaviour is that, for approximately 15% of the time, the renewable generation and aggregated demand balance each other out (zero values on the graph). During these times, the electrolyser is limiting its demand in order to avoid using energy from the mainland grid and/or from the thermal plants on the island due to the associated costs.

Finally, and perhaps most importantly, the area highlighted in red in Figure 7-5, shows that for approximately 14% of the time, there is a shortfall of renewable power to feed the power demand and, therefore, demand must be met using imports and/or the Sullom Voe plant.

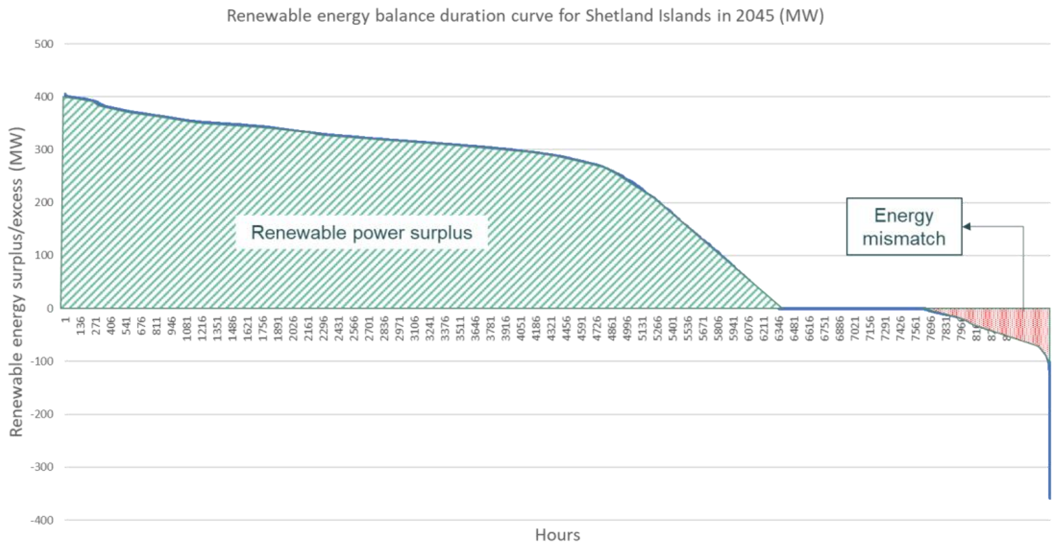


Figure 7-5 - Model Results: renewable energy balance duration curve for Shetland Islands according to

Figure 7-6 shows a sample weekday in January in which there is considerable surplus of renewable power throughout the day. It can be seen how, during periods of surplus, the electrolyser will seek to maximise its power output, making the most of the renewable power that is available and how, when the renewable power available drops, the electrolyser reduces its demand.

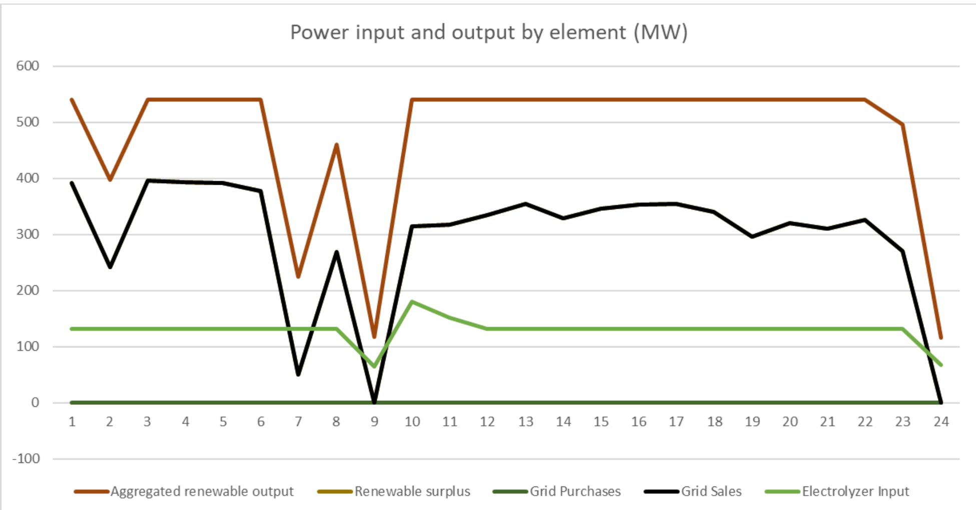


Figure 7-6 - Power input and export by element - sample weekday in January

For the opposite case, as exemplified by Figure 7-7, it can be seen how the electrolyser comes online during periods of shortfall of renewable power and electricity from the mainland grid is being imported. This occurs since, given that hydrogen demand must be met and that there is a limited amount of storage, the electrolyser occasionally relies on imported power plant to produce hydrogen; however, the import requirement is considerably low, to the point that they are hardly above the x axis.

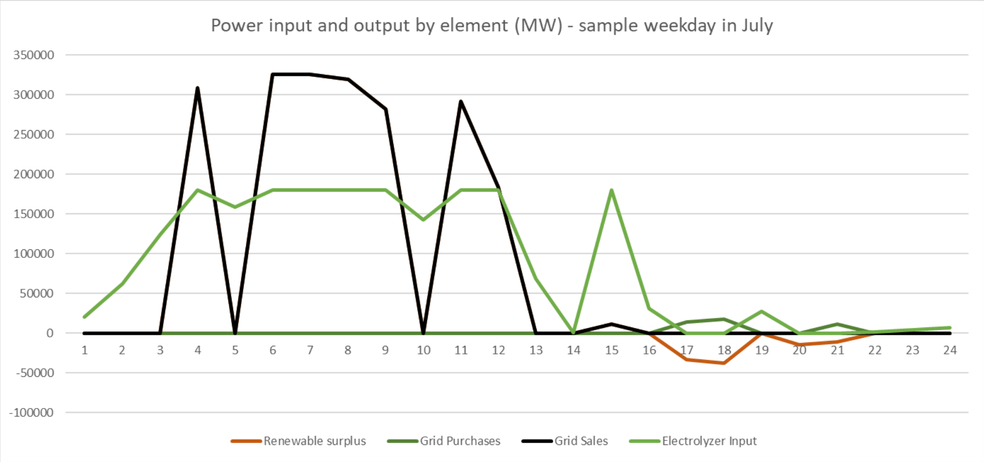


Figure 7-7 - Power input and export by element - sample weekday in July

Conclusions on island renewable energy balance

These results show how, considering the wind capacity pipeline, the Shetland Islands will be able to largely cover their energy requirements – both from local demand and hydrogen production – through renewable power. While the expectation exists that, for a fraction of the time, the islands will require import from the grid or the use of local thermal energy, it is worth noting that this would not happen for a significant proportion of the time.

Furthermore, the scenario considers the hydrogen demand in 2045, which is expected to grow significantly, but only considers renewable generation projects with planning permissions and that would be online before 2030. During the period between 2030 and 2045, there is a significant amount of time during which the renewable and/or storage capacity of the island can diversify and scale up to increase the renewable fraction of its energy system.

Analysis limitations and potential additions

The analysis considers hydrogen demand for shipping only – however, other sources of demand could appear before 2045 and could significantly change not only the overall level of hydrogen demand but also the daily behaviour and seasonality of it. This would have important implications for the sizing and location of infrastructure. Further studies could incorporate these other sources of demand and optimise infrastructure adequately.

A simulation of hourly or half-hourly wholesale market prices to capture the dynamics of local renewable and storage plants participating in the different power markets available would also add significant value to future simulations and studies. This would allow for a clear view on the economics of locally producing hydrogen by considering that renewable plants and storage assets would be participating in other markets (wholesale, balancing, ancillary services). The electrolyser size and operation would also be further optimised thanks to the consideration of time-dependent information on power prices.

7.5 Other aspects

Hydrogen production usually is efficient in certain temperatures and temperature control systems withdraw unnecessary heat build-up within the electrolytic cells with heat exchangers. This for the case of PEM could be around 60°C. Near the assumed location of the hydrogen production plant exists a heat collection facility which could benefit from the excess heat shown in Figure 7-2, and therefore an additional study is proposed.

8 Ammonia production

Ammonia will be produced with green hydrogen feedstock via the Haber-Bosch process. Nitrogen and hydrogen will react typically with iron-based catalysts under temperature of 400-500°C and pressures of 100 bar [41] [42].

$N_2 + 3H_2 \rightarrow 2NH_3$

This process needs to be a continuous operation to optimise the necessary flow rates, pressure and temperature to produce the required ammonia. This means that the fuel production process needs to be sized and designed accordingly to allow the continuous operation of the plant. Due to the seasonality of the pelagic trawlers' energy demands, interseasonal ammonia storage will be required to match fixed production and variable demand. Due to ammonia's toxicity, the plant cannot be located close to populated areas. The following options are considered possible:

- Co-location with the hydrogen production facility
  - Next to the Viking wind farm
  - At the Sullom Voe terminal
- North of Lerwick, near Greenhead with:
  - Hydrogen feedstock transported from Sullom Voe or Wind Farm via pipeline/trucks/bunkers
  - Hydrogen feedstock transported from facility co-located in Lerwick

Due to the large volumes required as feedstock for a continuous operation of the Haber-Bosch plant, the hydrogen plant should be closely located and connected by a short pipeline. Location near Greenhead also benefits from utilising the waste heat from the exothermic reaction by feeding it into the district heat network. The heat would otherwise be vented in more remote locations.

8.1 Daily requirements

The islands' annual requirement of approximately 42,000 tonnes of ammonia will be produced by continuous production of 115 tonnes per day throughout the year. As the RoRo ferries only require 300 tonnes per week, the excess ammonia will be stored, to cover the intense seasonal demand of the pelagic trawlers**.** The plant size and design for the case of Lerwick has similarities with the conceptual green ammonia plant from QNP [43] but differs into the buffering of ammonia. The QNP plant has a single ammonia buffering tank of 1,400 tonnes [44] while in Lerwick a buffer volume of over 20,000 tonnes is required to match supply and demand.

8.2 Footprint

The footprint of the ammonia synthesis plant for the maritime uses will be smaller than the conventional ammonia synthesis plants that exist today. This is because systems related to the steam methane reforming are not necessary as Shetland will have hydrogen feedstock from the electrolysis plant. These systems typically include desulphurization units, primary and secondary reformers, Water-Gas shift reactors, CO_2 separators, process air pumps, flue gas compressors and others. A reference in [45] estimated ~500m^2 per 1,000 tonnes of anhydrous ammonia production. In the case of Shetland, this might translate to ~20,000m^2 of land (150m by 150m) plot, which could be possible in the area north of Greenhead. Some depictions of a small scale 50 tpd plants are shown in [46] [47], which suggests having modularity in micro-scale plant of these capacities. For the storage of ammonia, a typical 20,000 tonnes storage tank is about 30 meters high with 30 meters diameter [48]. It would be appropriate to use multiple tanks for the purposes of safety, maintenance and redundancy, therefore an area of 100m by 100m is assumed at the Dales Voe location, in a safe distance from the population centre of Lerwick

Figure 8-1: Land plot of potential ammonia production-storage and bunkering facilities

9 Fuel transport

The following figure identifies the possible pathways for both fuels to arrive at the port of Lerwick to cover the respective demand. Two main production options were identified either colocation in Sullom Voe terminal or in Lerwick. This figure is important as it shows the transportation challenges that exist especially in the case of Sullom Voe which is 50km by road or 65km by boat and has daily requirements for both fuels of ammonia and hydrogen.

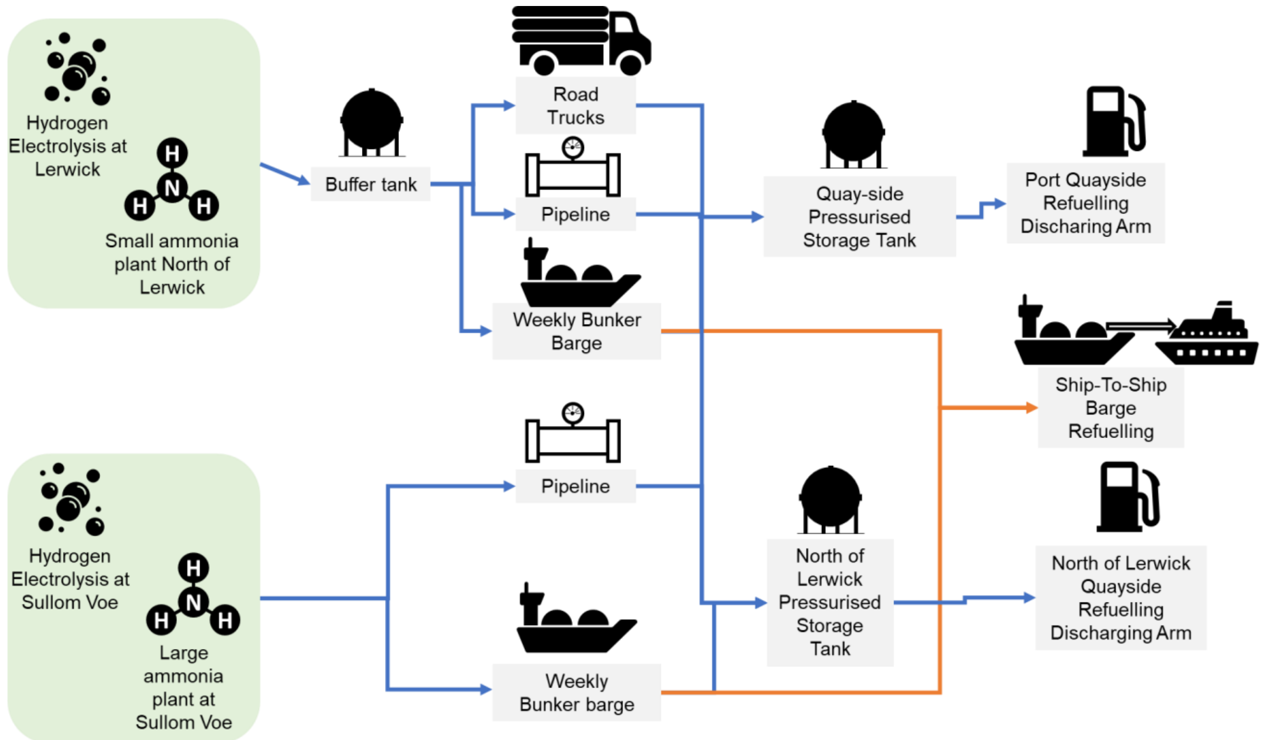


Figure 9-1 Potential hydrogen and ammonia transport options

For any production scenario or configuration, it is essential that hydrogen or ammonia are stored and readily available for vessels that need to refuel. This is particularly true for island communities, where ferries are a lifeline and seafaring activities are economically critical. The advantages and disadvantages of several production and refuelling scenarios are demonstrated in the Table below:

Refuelling location	Safety	Refuelling time	Production & Distribution Considerations
Lerwick port	Safety concerns of ammonia and hydrogen storage and handling near populated areas	Shortest	Local ammonia production plant probably unfeasible due to safety, requiring fuel transfer to Lerwick Tube trailer access possible for hydrogen only
North of Greenhead	Isolated from main population. Needs new quay to avoid industrial units	Some inconvenience – 2km from terminal in Lerwick. Area still sheltered	Located closest to likely ammonia and liquid hydrogen production and storage
Dales Voe shipyard	Isolated from populated area Exposed, relative to shelter or Lerwick by Bressay	Some inconvenience – 8km journey in opposite direction to Scottish mainland	Possibility for small decentralised hydrogen and ammonia production plant
Sullom Voe terminal	No significant safety concerns	Very long travel time from Lerwick, thus uneconomical and impractical	Large scale hydrogen and ammonia production and distribution
From bunker vessel at anchor	No bunker on dockside, ammonia denser than air, so would remain above water, not land Some risk in adverse weather	Multiple vessels may need to be available (one loading, one available) May not be possible to refuel while docked or loading passengers	Bunkering hydrogen vessels from hydrogen facilities at Sullom Voe/Dales Voe/Lerwick Bunkering ammonia vessels from ammonia storage facilities at Sullom Voe/Dales Voe

Table 7: Ammonia and hydrogen refuelling scenario aspects

For the case of Lerwick port, it is assumed that all production, transportation, storage and refuelling facilities are located close to Lerwick in various locations serving each facility's purpose.

9.1 Hydrogen and ammonia transport

Hydrogen transportation is challenging, in particular due to its low volumetric energy density. While hydrogen can be transported by a number of methods, the most cost-effective method varies dependent on the volume and distance.

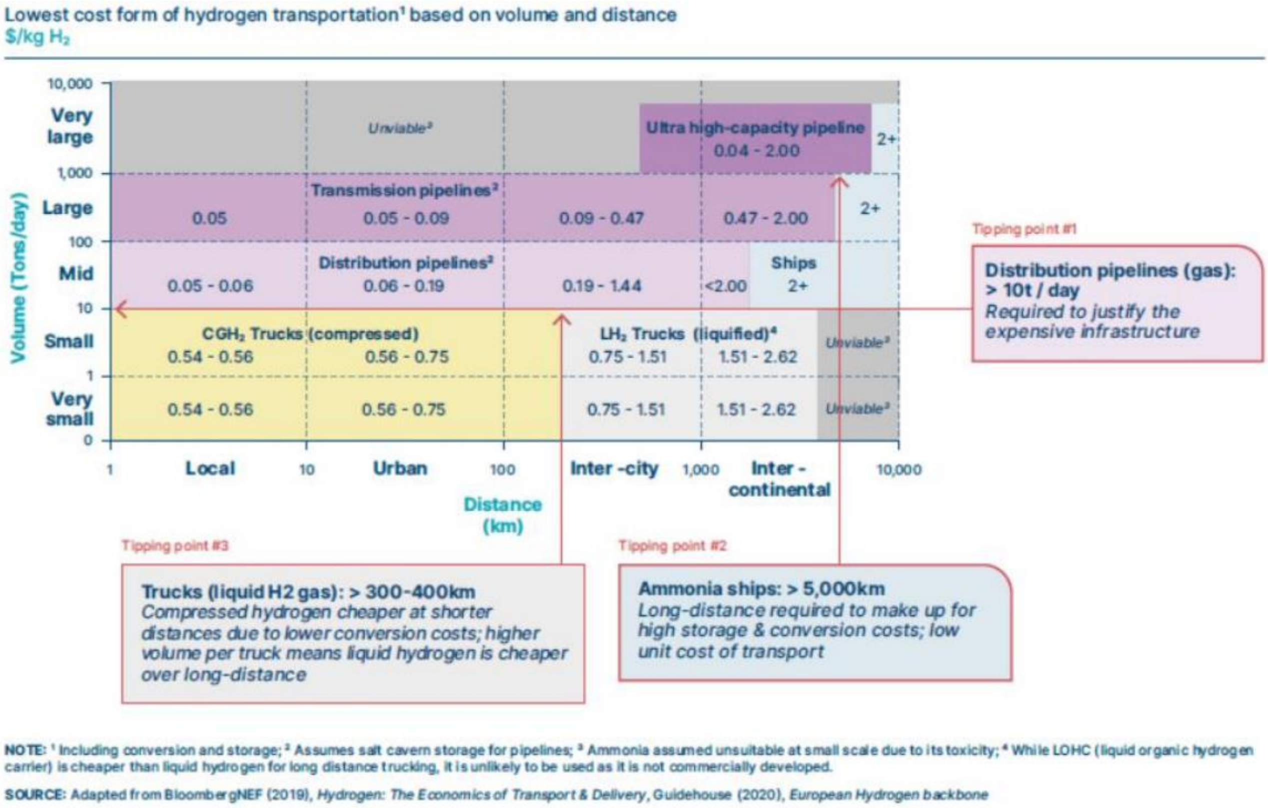


Figure 9-2: Most effective method of hydrogen transport. Source: Energy Transition Commissions

9.1.1 Pipeline

The cost of a new distribution pipeline network can be a substantial capital investment. However, pipelines are the cheapest method of distribution when demand is large enough. They are also the most efficient delivery method and reduce road traffic when compared against trucks.

Pipelines consist of two key components, the pipes themselves and the compressors that keep them pressurised. Transmission pipelines operate at 40 bar and distribution pipelines allow no higher than 7 bar. Note that ammonia liquifies around 8 bar at room temperature.

The H21 Leeds city gate project used a bottom-up analysis to estimate that the cost of a 450mm diameter buried hydrogen transmission pipeline would cost £1.05 million per km (2021 value)[3]. In comparison, the US DoE has a price goal of $200,000/mile, which is not dissimilar to the typical costs of current 6 inch natural gas pipelines. Based on these costs, assuming bulk production in Sullom Voe and consumption in Lerwick, a pipeline would cost somewhere between £4.4 million and £46 million. Cost for a pipeline in Shetland would be expected to be towards the lower end of this as there will be few land constraints and affected properties.

It should be noted that hydrogen has a high diffusivity when compared against natural gas. Polyethylene pipes are preferred for hydrogen.

9.1.2 Trucks

Trucks are a convenient means of flexibly distributing hydrogen at low volume to any specific point or over short distances, as shown in Figure 9-2. They have a lower investment cost than pipelines for lower volumes but are limited in how much they can carry by legal size limits allowed on UK roads. Storage vessels on trailers

[3] https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

are made of steel or carbon fibre to safely contain compressed hydrogen or ammonia. The fuel trailers themselves can act as local storage or buffering at production or consumption centres. However, the investment cost can easily become significant, with each trailer costing approximately £500,000. The volumes under discussion for this project are at the border between trailer and pipeline, so would require more detailed analysis to determine the cheapest solution.

Typically, hydrogen cylinders on trailers are pressurised to 350bar to 700bar, with between 250kg and 1000kg on each trailer. In comparison to a diesel tanker of equivalent size, approximately one tenth of the energy is carried, meaning far more journeys are required. If hydrogen were produced at Sullom Voe terminal, then hydrogen trailers could in theory be used to transfer the daily hydrogen requirement of 27 tonnes. This would result in 25-30 hydrogen tube trailer journeys, which is not felt to be practical given the required investment in many trucks, the traffic implications, and operating costs.

Ammonia tankers are capable of transporting ~24T of ammonia, which is three to five times the energy transported by hydrogen tankers. If ammonia would be produced from Sullom Voe terminal, then trailers could be used to transfer the ammonia fuel daily requirement of 150 tonnes for the RORO and the ~420 tonnes for a single pelagic trawler. This would require ~6 trailers for the RORO delivery per day, which may be practical in principle. However, in the case of the seasonal pelagic trawlers this is addition of 24 trailers. Both hydrogen and ammonia present safety challenges in road transport, though both are regularly transported in this manner today.

9.1.3 Bunker vessels

Given the location of Shetland's hydrogen and ammonia production and consumption being on the coast, transport of these fuels by sea is an interesting option. A bunker vessel could perform the functions of transport and dispensing, while eliminating the risks associated with onshore pipelines, transport and refuelling infrastructure. Indeed, LNG is often transported and bunkered in this manner today. The issue with bunker vessels is the high cost – a recent 3,500m3 LNG bunker vessel for Singapore cost $37 million.

9.2 Summary of fuel transport options

Should hydrogen and ammonia be produced in Lerwick, pipelines are the most effective means of transport infrastructure for:

- Hydrogen as feedstock for ammonia production. A pipeline that can carry daily 20 tonnes of hydrogen (800kgH_2/hour) is assumed.
- Hydrogen as fuel for the whitefish trawlers and the ROPAX. A pipeline being laid from the hydrogen production facility to the quay is assumed (~2-5km) that would carry 25-30 tonnes per day. Therefore, a flow rate of 1000-1250kgH_2/hour.
- Ammonia transport from North of Greenhead production plant to Dales Voe via underground pipelines as shown in Figure 8-1, seems to be the most reasonable option to effectively match the demand for fuel, with seasonal storage and bunkering.

  Ammonia production and transport from Sullom Voe appears impractical if it requires transport to Lerwick for the pelagic trawlers. However, if pelagic trawlers refuel at Sullom Voe, then only 6 tube trailers are necessary for the twice per week refuelling frequency of ROROs at Lerwick (likely near Greenhead.

10 Fuel Storage

For the majority of the ports and harbours on the Shetland Islands, the required refuelling and storage infrastructure is relatively simple, needing battery charging or in a few cases small or mobile hydrogen refuelling stations which could easily be supplied by truck from a central electrolyser location. However, Lerwick poses challenges due to the number of fuels required, the large volumes required, and health and safety risks associated with the port being in the islands' major population centre. Hence, this section of the report focusses on the storage infrastructure required at the Lerwick port in order to facilitate refuelling the fleet operating out of Lerwick for the reference year of 2045. The reason this timeframe has been chosen is because the fleet will have been fully decarbonised and therefore, represents the maximum local demand that needs to be planned for. The two green fuels that are assumed to be required at the port are ammonia and hydrogen. Current liquid fossil fuels are readily stored in large volumes in tanks near to the bunkering location, from small bunded tanks of a few m^3, up to large cylindrical tanks >10m wide. While flammable, current liquid marine fuels have a high flashpoint and have limited airborne or long range toxicity risks. Storage of future fuels near ports and population centres will undoubtedly be more challenging due to the lower volumetric energy density and safety concerns – mainly toxicity for ammonia and explosion or fire for hydrogen. Note that while methanol is not included in the fuel storage section (partly because it presents few challenges), a section is dedicated in the appendix for its production.

10.1 Hydrogen storage

Hydrogen is challenging to store – at room temperature and pressure it has 3,800 times lower volumetric energy density than diesel fuel. Therefore, compression or liquefaction are essential for practical energy storage. For smaller volumes, such as onboard road vehicles, or for the latest road trailers, hydrogen can be compressed to 700 bar, where the volumetric energy density is only 8.5 times less than diesel. However, achieving the strength necessary for these pressures for larger tanks is not practical and many "bullet tanks" only have a maximum pressure in the range of 20 bar. This makes large volume tank storage of compressed hydrogen impractical. For this reason, salt caverns are often proposed for large volume hydrogen storage, not only for the potentially vast volumes but also for the higher pressures of up to 200bar they can withstand. This makes them practical for monthly or even seasonal storage. For areas such as Shetland which do not have access to salt cavern storage, hydrogen can be liquefied for storage of large quantities of energy, increasing the energy density to around one third that of diesel. However, not only are the liquefaction plants expensive and the process highly energy intensive, but the gas will boil off over time and there are significant safety issues associated with liquid hydrogen. For these reasons, hydrogen is often proposed to be converted to ammonia for large volume storage and transport.

10.1.1 The case of Lerwick

Hydrogen will be required in Lerwick as a fuel for shipping and as feedstock for ammonia production. The following storage facilities have been designed/considered.

- A small hydrogen buffering tank at the ammonia production facility to ensure the continuous operation of the Haber-Bosch process
- A large storage facility for bunkering of the ROPAX and Whitefish Trawlers. The total hydrogen required to be stored daily is 25-30 tonnes, which would require one of or a combination of the following:
  - Thirty 40-foot shipping containers containing 300 bar hydrogen cylinders
  - Thirteen 15m high vertical cylinders at 200 bar
  - 10km of 24-inch pipe at 100 bar buried within an area of 200m by 200m.
  - In liquified state in a 350-420 m^3 tank
- It should be noted that in 2022, there is limited storage of storage of large volumes of hydrogen in this manner, so it expected that solutions for ports will evolve in the timeframe of this study

It is clear that any of these solutions would occupy a large area at or near the quay, which will pose issues for port operations, safety and visual impact. Bunkering barge vessels may be an option which could also provide flexibility for refuelling in different locations. Whatever solution is used, consideration must also be given to safely transferring the hydrogen from the storage location by pipeline, potentially across populated areas, though this is little different to transmission of domestic natural gas.

10.2 Ammonia storage

At room temperature and pressure ammonia is a gas. However, it is relatively easily liquefied, either by compressing above 8 bar or by cooling to just -33ºC. Both of these conditions are much easier to achieve and maintain than for liquid hydrogen. When liquefied, ammonia has slightly higher volumetric energy density than liquid hydrogen, or about one third that of diesel. Therefore, despite its toxicity, compared to hydrogen, ammonia is less challenging to store in larger quantities. Ammonia is typically stored today at 10 bar for smaller volumes (typically maximum 300t for a single storage unit) or low temperatures around -33ºC for larger volumes (up to millions of tonnes).

10.2.1 The case of Lerwick

It is unlikely that storing large volumes of ammonia near the population in the ports of Shetland will be possible in the same manner as liquid fossil fuels today. Therefore, as discussed above, ammonia could be produced in the area North of Greenhead while ammonia could be stored at the Dales Voe dock where it is isolated from the population of Lerwick in a ~3km horizontal distance. Pipelines could transfer ammonia from the production plant to the storage tanks via a pipeline network which is also connected to the bunkering infrastructure in the North of Greenhead as shown in Figure 8-1.

The following storage options for the case of Shetland islands:

- Large scale stationary tank for seasonal storage – these typically can store from 1,000-50,000 tonnes of ammonia and could act as a seasonal storage for Shetland. An example of the size for 20,000 tonnes seasonal storage is shown in Figure 10-1. Depending on the application and design specification one or multiple smaller ammonia storage tanks could be considered for the case of Lerwick.
- Mobile storage vessels which can act as well as bunkering vessels in a similar fashion to current LNG bunkering practice. A vessel of similar type to the M/T Coralius small LNG bunker ship [51] would be appropriate. This would require a significant investment of the scale of several tens of millions of pounds per vessel.
- Tube trailers/trucks (or bullets) which typically store approximately 24t of ammonia. These could only be used to transfer ammonia fuel to the bunkering facilities. But since the RORO and pelagic trawlers have a single refuelling amounts ranging from 150-420 tonnes. This would translate to a fleet of 6 tube trailers for the RORO and a seasonal addition of 24 more trailers, which makes it uneconomical and unpractical solution.

Figure 10-1: (left) example of 20,000 ton liquified ammonia barge (right) example of a 20,000 tonnes ammonia storage tank

11 Fuel Bunkering

Bunkering facilities need to be provided for both fuels near Lerwick. The different methods, technologies and refuelling rates per fuel are discussed in the following subsections.

11.1 Bunkering hydrogen

There are a number of options for hydrogen bunkering in shipping. The following are presented in the Rhine programme for bunkering hydrogen for inland shipping [53]:

- swapping of tank-containers, which obviate the need for refuelling infrastructure and reduce bunkering time
- fixed portside bunker stations – long-term solutions that can achieve high volumes of bunkering
- truck-to-ship – which may be suitable for ports with low volume requirements or where vessels dock in a variety of locations. Limited to ~1T compressed hydrogen per truck
- ship-to-ship – potentially very high volumes, flexibility for access to different vessels in different locations or to transfer hydrogen from a distant storage location.

For the case of bunkering with swappable tanks while the refuelling rates are not important at the dock, it is crucial to have sufficient amount of tanks to store hydrogen in Lerwick and then utilise it for the vessels. Also, since different types of vessels with different tonnage will use hydrogen, it will be challenging to use a standardized solution to fit all vessels, though the solution is appealing from a time and infrastructure point of view. Additionally, designing a trawler to accommodate a shipping container on deck, together with the ~20T weight of the ISO container will be prohibitive. However, this could be an appealing option for vehicle ferries, where the container could be simply driven on.

For the case of bunkering compressed hydrogen, bunkering could be accomplished with the following methods:

- Using compressors – the fuel is stored at a lower pressure within a storage system or pipeline and then compressed into the ships. This is cheaper but refuelling is slower. The compressors have a significant energy and cooling requirements. Use of compressor with pre-cooling would achieve rates of 215kg/h per compressor.
- Pressure balancing – the fuel is stored in a storage tank/cascade system, at a higher pressure then required on the ships. This pressure differential drives the refuels. Once pressure equilibrium is reached refilling will stop, and either a compressor or a cascade filling system is required. Refiling in this way is faster but may be more expensive due to the costs associated with the high-pressure storage vessels. Also, many cascade tanks would be required to cover the large daily demand of 25t of hydrogen for the ROPAX vessels. Conservative estimates inspired from the automotive refuelling mention rates of 130kg/hour but some companies claim that it is possible to achieve even 3,000kg/hour [53].
- Depending on the technology used, the refuelling times could range from:
    - 0.5-4 hours (tugs) (which will not be problematic as tugs are assumed to refuel once a month)
    - the whitefish trawlers could result in 8 hours, which is not an issue for an overnight refuelling per vessel but since 14 trawlers are refuelling each week, then at least 2 refuelling rigs will be required at the port with a stationary 500 bar storage.
    - For the ROPAX which requires 25 tonnes, refuelling using a single refuelling rig of current types will take an impractically long time. It is anticipated that in the timeframe from now until the hydrogen ferries come into service that new technical solutions will become available.

The flow rates for bunkering liquified hydrogen are more promising - from 1,000-4,000kg/hour. A typical cycle for bunkering 1,000kg of liquid hydrogen are broken into 40 minutes for cooldown, 30 minutes for transferring and 30 minutes for purging and warming up prior to disconnection [53]. The case of liquid hydrogen is explored in the Appendix in section A1.1.

Regardless of the physical state of hydrogen to be bunkered multiple hydrogen dispensers are required. Not only is there is a probability that the mainland ferry, tugs or whitefish trawlers may need refuelling at the same time, but also that they dock at different areas of the port. The worst-case scenario of 14 whitefish trawlers refuelling 0.5t of hydrogen each is considered unlikely and could potentially be resolved with digitised logistics handling. A further implementation study could inform the precise number and location of hydrogen refuellers.

11.2 Bunkering ammonia

Loading of ammonia as a cargo takes place in ~120 ports worldwide, meaning the equipment and safety cases are relatively well understood. Due to the high uptake of LNG, ship-to-ship bunkering techniques and availability has increased as well, which could be one of the solutions as it minimizes investments and provides flexibility on providing fuel where is required.

For the case of Shetland and regardless to where the fuels would be produced or stored, the following refuelling options could be considered:

- Refuelling from barge to ships
- Refuelling from trucks to ships
- Refuelling from quay-side infrastructure to ships

For the 2 vessel types, the single maximum refuelling amounts assumes are 150 tonnes for the RORO and 420 tonnes for a pelagic trawler.

- The RORO vessels currently refuel twice a week and they typically spent **1.75 hours per week to refuel**. Therefore, it is essential that a similar pattern is also used for this vessel. As ROROs remain in Lerick for 8-10 hours, this time could be used to safely bunker fuel at the North of Greenhead location. Further investigations on the logistics of this operation are advised.
- The 7 pelagic trawlers in Lerwick have a seasonal pattern mostly happening between September and January and little demand in Spring months. This is fish species and catch dependent. There is no requirement for a rapid refuelling rate for pelagic trawlers.

In [52], refuelling rates for bunkering ammonia to a passenger vessels with similar ranges of ammonia requirements are reported. A total of 1.6 hours is mentioned for quantities ~200 tonnes. This is in similar ranges for import of ammonia in a port terminal as shown in Indonesia's Ammonia Export Terminal Kaltim Pasifik Ammoniak which receives at a rate of 90 tonnes per hour [54]. Therefore, it is assumed that for both ROROs and pelagic trawlers 1-3 hours would be necessary for the 150 tonnes for RORO and 420 tonnes for pelagic trawlers. It would be challenging if pelagic trawlers need to refuel at the same time as the RORO. Therefore, at least two dispensing systems should be installed as indicated earlier in Figure 8-1. Ammonia can be pumped in and out of vessels with a liquified ammonia discharging arm using special pipes and valve systems similar to LNG bunkering [55].

There are several logistical challenges as to where the vessels will be refuelled/bunkered.

- Refuelling the RORO where it docks is challenging as it is directly at the centre of Lerwick city posing challenges in terms of safety.
    - While the safe distances for ammonia and LNG are similar, currently LNG bunkering at the quay requires a number of safety measures potentially including road and business closures, evacuation planning etc. In addition, even small non-dangerous discharges will be unpopular with residents due to the smell.
    - Ship-to-ship bunkering from an ammonia barge has lower risk as there is no landside infrastructure and the ship being refuelled is between the refuelling point and the land.
- The Pelagic Trawlers are currently refuelled by truck at the marina in the North of Lerwick. As with the ROROs, the safety issues of ammonia refuelling are significant.

For the pelagic trawlers, bunkering in the vicinity of Greenhead will pose minimal issue for the time available and number of times per year it is required. For the RORO, the Greenhead option adds travelling time, complexity and cost to each journey. Therefore, it will be highly beneficial if Lerwick Port Authority can work on a safety case with the relevant authorities to enable a bunkering option within the existing port area

12 Conclusions

All of the future fuels (with the exception of biodiesel) have lower volumetric energy density and higher cost than existing liquid fossil fuels, making their introduction challenging without incentives. Where possible, vessels should be decarbonised by battery electrification. This is possible where the range is relatively low, where regular recharging is possible, or where “hybridisation” for longer journeys is practical. Compressed hydrogen can be used where energy requirements are not excessive, or where there is significant available space above deck. For larger vessels that are not passenger-carrying, liquid ammonia may be suitable, while liquid hydrogen may be suitable for passenger vessels, though there are challenges regarding space usage. Methanol is attractive from a vessel point of view due to ease of handling and use, however, there is a shortage of biogenic CO_2 on Shetland, and costs are likely to be prohibitive. Biodiesel is similar in outlook to methanol, in that it is easy to handle, but there is a shortage of local feedstock and prices are likely to be prohibitive. The most likely future fuels for Shetland’s domestic fleet are shown below:

Mainland ferries:	Ammonia or hydrogen depending on future safety case
Interisland ferries:	Battery electric, except Fair Isle, Skerries and reserve ferry which require hydrogen
Tugs:	Battery/biodiesel (or methanol) hybrid or hydrogen/biodiesel dual fuel
Pelagic fishing:	Ammonia or methanol
Whitefish trawlers:	Compressed hydrogen
Small fishing boats:	Battery electric
Aquaculture:	Pontoons: direct wired electrification, support vessels: battery

A large number of offshore support vessels visit Shetland but are highly varied and tend to also visit a large number of other ports. Therefore, their decarbonisation pathways are not considered in detail. However, their current fuel usage is significant, and it can be assumed that there will be pressure to decarbonise, especially for windfarm and O&G decommissioning. The same trajectory is assumed for the cruise ships which infrequently refuel in Shetland currently. Therefore, it is likely in future that these vessels will consume a large amount of future low-carbon fuels from Shetland. Based on the fleet replacement timescales, by 2035, approximately one third of the current fuel use will be from low carbon fuels, and all vessels will be using low-carbon fuels by Scotland’s 2045 net-zero date.

The Shetland Islands and the surrounding seas have exceptional wind resource. The current installed onshore wind farms have a capacity of ~11MW with very high-capacity factors. Future onshore plans will increase this to ~700MW, starting to come online in 2024, which will be capable of overloading the proposed 600MW interconnect to the Scottish mainland. Furthermore, there are plans for many more gigawatts of offshore wind capacity. Calculations show that the proposed renewable generation plans are capable of powering the islands and any projected marine hydrogen demand many times over. While generation is capable of supplying hydrogen demand, there may be some challenges on the local grid infrastructure where ferries may need charging overnight simultaneously with domestic electric heating (which will replace oil-fired heating in future). The energy from waste plant could be a useful source of CO_2 for local methanol production, however volumes are insufficient to meet projected demand. This could potentially be supplemented by CO_2 from direct air capture. By integrating the waste heat from electrolysis and methanol production into the district heat network, the economics of methanol production can be improved, however, the plant size is likely to be too small for economic methanol production unless technologies change in future.

The decisions on where to site electrolysers will depend on a number of factors. Should a large industrial site commence production at Sullom Voe, for example, the likely low gate price of hydrogen may make it economic to transport hydrogen by pipeline (or for smaller quantities by road) to Lerwick. However, if there is no visibility of industrial production, it may be most appropriate to produce hydrogen near to the demand centre to minimise transport costs. The shortest pipeline can be achieved with a location to the West between Holsgarth and Gremista. Alternatively, the Greenhead area is most promising to avoid populated areas. Should ammonia be produced locally, the Greenhead area is most appropriate, potentially using Dales Voe for interseasonal ammonia storage, well away from the population, but close enough to allow for large scale refuelling just to the North of the existing Greenhead quayside. The large volumes of hydrogen needed to be stored near the port will pose significant challenges for sizing of infrastructure, safety and potentially visual impact. The decisions on how to store and dispense hydrogen may become clearer as the technology progresses.

13 Recommendations

While this study shows that maritime decarbonisation in line with Scotland's 2045 net-zero target is possible, further studies will be necessary to confirm the feasibility and challenges.

- The fact that the Shetland Islands have a captive local marine fleet means the area represents an ideal opportunity to trial decarbonisation solutions prior to rollout elsewhere. It is recommended that Shetland Islands Council investigate all opportunities to fund demonstrations and trials of vessels and landside facilities at the earliest opportunities. Given the interest from renewables developers, they could be an alternative source of funds to government.
- The mainland ferries are both the lifeline to the islands and also among the largest energy users. Therefore, the design of their replacements needs to carefully consider which fuels they may use in future, to avoid very challenging retrofit. Decisions on these fuels will affect not just the ferries but also fuel production and infrastructure on the Shetland Islands, so need to be performed as a priority.
- While the exact choice of fuel for several vessel types is currently unknown, many of them are likely to be hydrogen based, so feasibility studies into electrolyser locations can be undertaken at little risk. These should consider the broader decarbonisation aspirations of the islands as well as potential industrial scale projects.
- Decisions around future planning permission should consider the potential need for electrolysers, electrofuels plants and fuel storage. Likely areas of interest are inland between Holsgarth and Gremista and around Greenhead.
- Investigations should be performed into the capacity of the electrical grid near the ports where the battery-electric ferries will recharge, considering the likely future demands for electrification of homes and vehicles
- The large quantity of hydrogen to be stored near the port will pose challenges. Further techno-economic studies and supplier engagement will be required to understand the most practical and cost-effective method of storage and dispensing

A1 Consideration of landside implications of methanol and liquid hydrogen to enable retrofit

Project partners Babcock analysed the possibility of converting the existing fleet to alternative fuels. They found that most of the ships assessed were too limited by their hull and storage space to be able to accommodate sufficient quantities of compressed hydrogen. They also determined that ammonia was too great a safety risk on passenger vessels due to its toxicity.

The studies determined that alternative fuels should be used for some of the vessels. The alternatives are shown in the table below:

	Tugs	Pelagic Trawlers	Mainland ferry RORO	Mainland ferry ROPAX
Base case scenario	Dual fuel	Ammonia	Ammonia	CH2
Retrofit scenario	Methanol	Methanol	LH2*	LH2*

Table 8: Fuels required under retrofit scenario

The pelagic trawlers and mainland ferries are also the largest demands for fuels on the island. In the base case scenario, the mainland ferries were assumed to be replaced with vessels designed to be fuelled on ammonia and hydrogen and would switch refuelling from Aberdeen to Lerwick from 2035. In the retrofit scenario the vessels are only capable of storing enough liquid hydrogen for a one-way voyage and therefore will need to refuel in both Aberdeen and Lerwick. This annex serves as an analysis of the land-based infrastructure implications of following this scenario. The analysis is based on an outlook to the year 2040 when all the fleets in Table 8 have transitioned to alternative fuels. This also gives time for fuel production technologies to improve in cost and efficiency.

A1.1 Liquid hydrogen

Hydrogen can be converted to a liquid when cooled and sustained at an extremely low temperature of -253ºC. The benefit is a significantly higher density of 71kg/m^3 compared to 24kg/m^3 when compressed at 350 bar and 40kg/m^3 when compressed to 700 bar. This increase in volumetric energy density enables transport of larger quantities of hydrogen or to take up less space on hydrogen powered vessel that aims to maximise on-board space for transporting goods or people.

Liquid hydrogen is difficult to handle due to its extremely low temperature. Transporting and storing liquid hydrogen requires careful handling and advanced vacuum-insulated vessels. If not stored at the right conditions, hydrogen can begin to evaporate causing pressure build up within a vessel. Evaporated hydrogen would either have to be reliquefied at an extra energy cost[4] or simply released into the atmosphere for an energy loss (or consumed as fuel onboard a vessel). Despite the level of insulation in a storage vessel, the temperature difference between the liquid hydrogen and outside atmosphere will cause boil off to occur over time.

Hydrogen liquefaction is considered an established technology for sectors such as aerospace but has yet to be effectively commercialised for wider markets. A study by Cardella et al showed that through new designs and exploiting economies for scale both capital costs and operating costs can be reduced by up to approximately 65%. IDEALHY, a 2013 study commissioned by the Fuel Cell and Hydrogen Joint Technology Initiative (FCH JU) reviewed hydrogen liquefaction technology concepts and found a plant could be developed for approximately half the investment of existing plant technologies. Applying this theoretical cost basis for the demand of the mainland ferries under the retrofit scenario comes to estimate of £39 million [53] for each site in Lerwick and Aberdeen. Assuming a 20-year lifespan and 8% interest payments (and ignoring maintenance), liquefaction plant costs would add approximately £1/kg to the cost of hydrogen.

[4] Assuming it has access to liquefaction infrastructure

Hydrogen liquefaction is a very energy-intensive process due to the extreme temperature requirements. Existing liquefaction plants have a typical specific electricity demand of over 10kWh/kgH_2 but further process improvements are expected reduce this to 6kWh/kgH_2. Considering its large energy demand, reducing the cost of electricity is the most impactful way to reduce the overall cost of liquefaction. Assuming a 30p/kWh electricity price, the liquefaction process will add approaching £2/kg to the cost of hydrogen, giving a total additional cost of approximately £3/kg for liquefaction.

Liquefaction is an expensive, energy intensive process and liquid hydrogen is difficult to handle. However, studies have shown that there are opportunities for cost reductions that could make it a feasible solution for bulk transport and storage. The matured liquified natural gas industry has shown that the challenges with transporting and handling very low temperature liquids is feasible and gives opportunity to transferring skills.

A1.2 Methanol

Synthesis of methanol is a commercial process that has been in use for 80 years. Coal was initially used as the main feedstock, more commonly it is now produced from natural gas. It is typically produced by the Fischer-Tropsch process where synthesis gas (a mix of hydrogen, carbon dioxide and carbon monoxide) reacts in the presence of a catalyst. Methanol can be a sustainable fuel if it is produced using zero carbon hydrogen and sustainably sourced CO_2.

Methanol should not be produced using blue hydrogen. Splitting hydrogen and carbon from a fossil fuel source only to combine it once again is a waste of energy. A less energy intensive system with less infrastructure requirements would be to continue using fossil fuels and offset the emissions through carbon negative technology. Ultimately, the goal of decarbonisation is to eliminate dependence on fossil fuels and so combining hydrogen from electrolysis with sustainably sourced carbon is the only recommended production process.

Several aspects for producing methanol are different when utilising pure CO_2 as opposed to a mix of CO and CO_2. The reaction is less exothermic meaning lower cost, higher efficiency and simpler cooling methods are used. However, pure CO_2 streams are also less reactive which may lead to larger reactors being needed.

Unlike ammonia and hydrogen, methanol is a liquid at ambient temperatures. A core benefit of this is that existing infrastructure can be utilised with little modification. This also applies for a vessels on-board storage and powertrain making methanol an extremely attractive fuel for retrofit solutions. While methanol has less than half the volumetric energy density of diesel like fuels, once the container is considered, it has higher volumetric density than LNG, and significantly higher volumetric energy density than hydrogen or ammonia. An important safety risk compared to other hydrocarbon liquids such as diesel and petroleum is that methanol has a low flash point making it easier to inflame.

A1.2.1 Sustainable CO_2 sourcing

A1.2.1.1 Point of source capture energy from waste plant

While Shetland is blessed with excellent wind resources, nowadays it is not blessed with abundant sources of biogenic carbon. There have been discussions around CO_2 being sent from the Scottish mainland to Shetland for sequestration in disused oil and gas fields, however this CO_2 is likely to be fossil-sourced and would not be appropriate for use in “green” fuels. The Lerwick energy recovery plant burns municipal solid waste (MSW) to produce energy. Typically, more than 50% of MSW is biogenic, which would potentially allow carbon captured from this plant to be used for development fuels under renewable transport fuels obligation (RTFO). Given the potential for this CO_2 to be used to power the local fleet, together with potential synergies around waste heat from the process being fed into the district heating network (DHN), a study has been performed to review the potential. This is shown in more detail in Appendix 2.

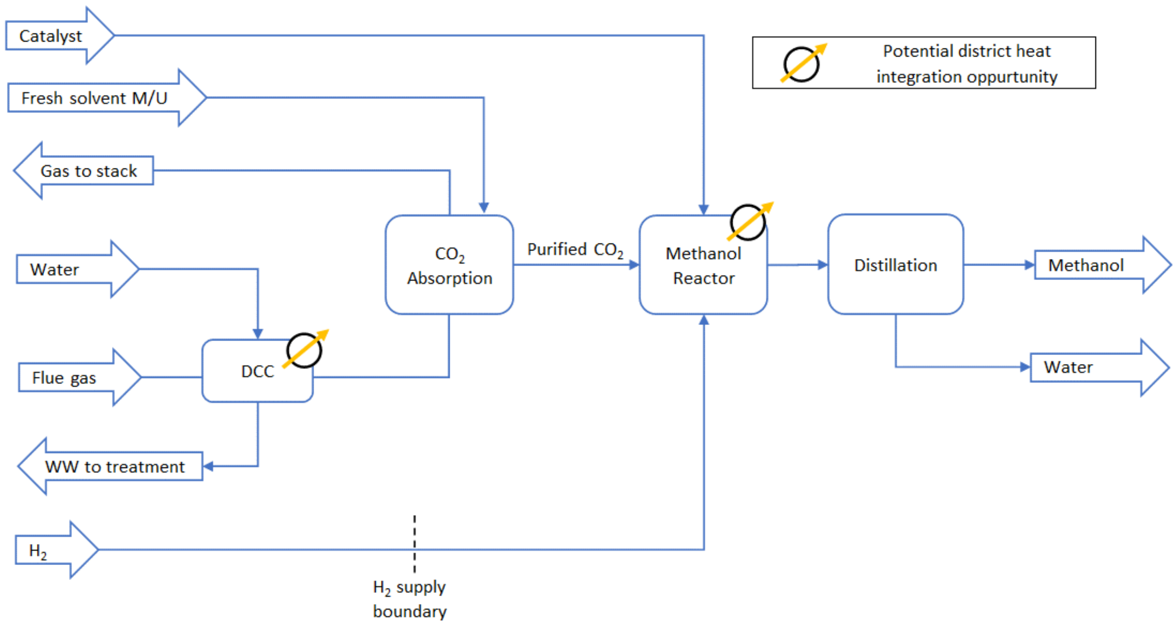


Figure 13-1: block diagram for CO_2 absorption and methanol synthesis

It is envisaged that the direct contact cooler (DCC) and methanol reactor would be integrated into the DHN, as a source of revenue for the system, and to boost the heat supply to the DHN. 1T of MSW generates 700-1,200kg of CO_2. Given ~22kT of MSW/year, the plant can capture ~18kT of CO_2 and generate ~12kT of methanol/year. As this is below the amount of methanol needed by future vessels on Shetland, and as a price comparator, direct air capture of CO_2 has also been considered.

A1.2.1.2 Direct air capture

Direct Air Capture (DAC) is a novel process to capture carbon directly from the atmosphere. DAC is therefore seen as a carbon negative technology when CO_2 is sequestered or carbon neutral when CO_2 is utilised in fuels. Provided it is powered by renewable energy, it has the potential to provide limitless sustainable CO_2 at scale. Unfortunately, it utilises a high amount of energy to capture the CO_2. Relative to a combustion flue, CO_2 is dispersed in the atmosphere and therefore more volume of air must be processed to achieve the same output. Because of this DAC is likely to remain more expensive than flue captured CO_2 for some time to come. Levelised costs of the CO_2 are currently between \$300 and \$600 per tonne of CO_2 but are expected to decrease substantially to \$50 to \$150 in the future as technology is improved and scaled

Various technologies exist but the most promising are solid sorbent capture which have a lower heat requirement of 100ºC compared to 900ºC required of liquid sorbent capture methods. DAC's require the heat to separate CO_2 captured by the sorbents for storage. Sourcing heat can be a challenge, as electrification or green hydrogen significantly increase system power demand. The best opportunities for DAC involve utilising natural geothermal heat or waste heat from industry.

Hotter countries are favoured for DAC locations as less energy would be required to meet heat requirements. DAC on Shetland would therefore, have lower operational efficiency due to the colder climate and cooling winds. The salty sea air would also degrade components unless taken into consideration in the design, likely raising costs. However, Shetland is still a suitable site for DAC as nearby siting saves energy and costs related to CO_2 transportation.

A1.2.1.3 Biogenic CO_2

Biogenic CO_2 is derived from plant material that capture CO_2 throughout their lifecycle. Therefore, utilising biogenic resources as a CO_2 source is a carbon neutral process provided the resource is sustainably regenerated. The definition of sustainable regeneration is a contentious topic. Production of biofuels from energy crops could displace food supply, causing negatively impacting indirect land use changes[5] elsewhere in the world to meet demand. Generally, residue by-products or waste are seen as sustainable biogenic

[5] Such as deforestation or conversion of peatland

resources that have little if any regulatory constraints for use. Some examples of how biogenic CO_2 could be sourced include capture from:

- The fermentation process used to create bioethanol
- The upgrading process to biomethane from biogas produced by anaerobic digestion
- The flue of combustion of biomass resources

Shetland Islands local bioresources are limited, however, there is a significant amount of organic waste because of the fishing industry. The fatty lipids in fish waste can be used to produce bioliquids or biogas through an anaerobic digester. However, unlike DAC, the potential for CO_2 supply is limited by the availability of the fish waste and is only likely to fulfil part of the methanol CO_2 demand. The redirecting of fish waste from the energy from waste plant to another process could also cause the EfW to not meet its sustainable carbon content threshold, disqualifying it from being utilised as a CO_2 source.

A1.3 Cost difference

Levelised cost of energy calculations show the difference in costs for each fuel presented in the table below. An electricity price of £44/MWh was selected to simulate the cost of an onshore windfarm developed in 2030[6]. Plant costs were selected based on cost reductions expected by 2040. Compressed hydrogen was found to be the cheapest fuel due to the relatively low amount of plant equipment required. Most of the cost is associated with the electrolyser and the electricity cost to produce the hydrogen before compressing it to 350 bar. This significant cost element is included in as the cost of hydrogen feedstock to each of the further fuels shown in the table below.

	Compressed 350 bar	Ammonia	Liquefaction	Methanol EfW plant	Methanol Direct air Capture
GBP per MWh of fuel (NCV)	89	177	233	161	201

The next most affordable fuels is methanol produced using CO_2 captured from the Lerwick energy from waste plant. The synthesis of methanol is an established technology, however there may be reductions in costs for small-scale systems such as this. Energy costs are minimal as the process is exothermic, producing enough heat to meet process needs and power onsite generation.

As with methanol synthesis, the Haber-Bosch process used to produce ammonia is a well-established process commonly used to create fertilisers. There is a limit to the cost reduction achievable with this technology. The reaction is exothermic, so heat and power needs are minimal.

Methanol using CO_2 sourced from direct air capture is the second to last most expensive. The cost lies in the expense in construction and relative inefficiency of direct air capture technologies. This fuel cost does consider a cost reduction attributed to the wider adoption of the direct air capture technology into the future and leveraging waste heat from the methanol synthesis plant.

The most expensive fuel is liquid hydrogen. This was despite modelling around a conceptual lower cost and higher efficiency plant. Unlike the other plants however, liquefaction lost out on economies of scale as the mainland ferry was determined to only be capable of a one-way trip between Lerwick and Aberdeen meaning that two smaller plants were modelled as opposed to one large plant.

6 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

A2 Feasibility study on production of methanol in Shetland

A2.1 Introduction

Methanol can be produced through several different pathways, one such route that could be considered is to react the hydrogen with a concentrated source of carbon dioxide (CO_2). The sources of CO_2 in the area are fairly limited, one option is however to recover the CO_2 produced at the Lerwick Energy from Waste (EfW) facility. The intent of this appendix is to evaluate this potential value proposition.

A2.2 Background

A2.2.1 Overview of the Lerwick Energy Recovery Plant (Shetland)

The EfW plant in Lerwick is operated by the Shetland Isles Council. It burns ~23,000 tonnes / annum (A2.0) of waste originating from Shetland, Orkney and areas of the Highlands. The facility produces 7MW of energy in the form of heat and hot water for the district. The facility has been operating since 2000. In 2011 the facility's control system was updated (DCS replacement project)[7]. Further upgrades were installed in 2021 to improve the plant efficiency, heat output and operational lifetime[8].

A2.2.2 Capturing of CO_2 from EfW facilities

The amount of waste that is combusted by the EfW facility can be used to provide an estimate of the amount of CO_2 that is generated in the flue gases and can therefore be captured. For initial high-level studies (and without completing a detailed assessment of the CO_2 that is generated, which is a function of waste composition) one can estimate that 1 tonne of Municipal Solid Waste (MSW) typically produces between 700–1,200kg CO_2[9]; a value of 900kg CO_2[10] per tonne is assumed for the purposes of this study.

There are several carbon capture techniques that could be considered to extract CO_2, these include pre-combustion, combustion and post combustion options. Given that the proposal focuses on capturing CO_2 from an existing facility, the technology focus is on post-combustion capture from post-combustion flue gases. Table 9 below covers the various technology options that are available, as well as the corresponding Technology Readiness Level (TRL)[11&12].

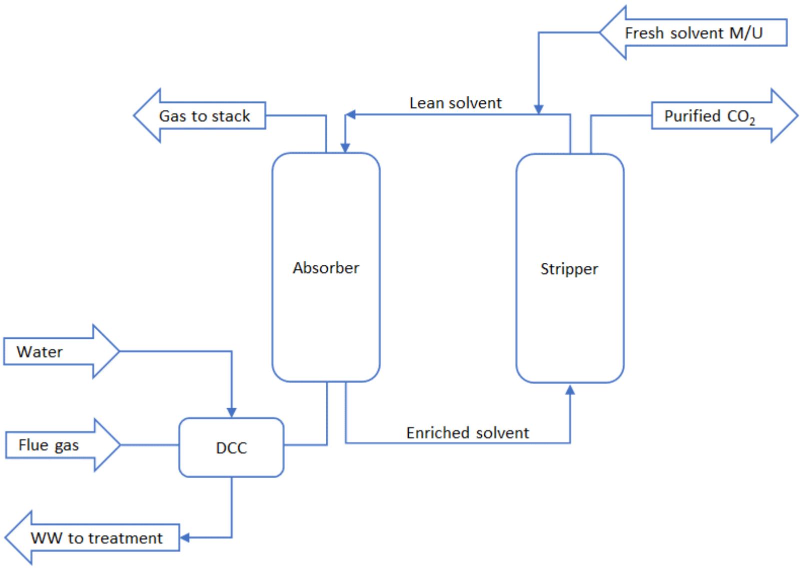
Table 9: Overview of TRL levels for various CO_2 Capture technologies

Technology	Application	TRL level
Adsorption: CO_2 is adsorbed onto porous particles e.g. non-$CaCO_3$ or non-zeolites	Mainly applied in natural gas and ethanol processes. Not yet widely applied in EfW	8
Absorption: gas is transferred from gas to liquid phase to separate from other gaseous components e.g. amine solutions and then released back into gas phase	The most advanced technology from an efficiency and economic viability perspective. Demonstrated in small and large power generation, fuel transformation or industrial production plants	7
Membrane separation: CO_2 selectively permeates through membranes	Applied on many biomethane to grid sites. Its application is currently in the demonstration phase with a few commercial examples.	6-7
Chemical capture: makes use of chemical reactions with carbon dioxide to obtain final products which can be inorganic or organic, normally carbonates.	Relatively new technology requiring the need for large scale pilot testing.	4-6

7 WMW | Shetland Islands Waste to Energy Facility Gets Upgraded Controls (waste-management-world.com)
8 https://www.shetland.gov.uk/news/article/222/operational-note-energy-recovery-plant-upgrade
9 https://www.ipcc-nggip.iges.or.jp/public/gp/bgp/5_3_Waste_Incineration.pdf
10 https://www.ieabioenergy.com/wp-content/uploads/2013/10/40_IEAPositionPaperMSW.pdf
11 Technologies for carbon dioxide capture: A review applied to energy sectors - ScienceDirect
12 Technology-Readiness-and-Costs-for-CCS-2021-1.pdf (globalccsinstitute.com)

The most well proven technology is the absorption process based on the use of a chemical solvent, such as various amines e.g. Monoethanolamine (MEA) or Tetraethylenepentamine (TEPA)[13], alkali (e.g. potassium carbonate) or physical solutions This study will therefore focus on the application of absorption (and use of a solvent) as the preferred method for post-combustion CO_2 removal. This process is estimated to be able to capture at least 90% of the CO_2 in the flue gas (some sources quote capture levels of up to 95%). A high-level overview of the process is provided in Figure 13-2.

Figure 13-2: High level block flow diagram for capturing CO_2 via absorption



It is important to note that the flue gases typically exit an EfW facility at around 130 – 170 °C. In the scheme above a Direct Contact Cooler (DCC) is typically used to cool the gases down to 40 – 60 °C prior to it being fed to the absorbing columns[14], alternative types of heat exchangers could be considered for heat integration and recovery. Heating (via steam, not specifically indicated above) and cooling is required for solvent recovery, thus also making further heat integration options available. The wastewater generated in the DCC typically then requires treatment (as would contain impurities scrubbed out gases). Table 10 provides an overview of the typical inputs and outputs required for the process[15&16]:

Table 10: Typical inputs / outputs required for CO_2 absorption

Technological metric	Value	Units
Liquid / gas ratio	Approx. 4:1	[kg solvent/kg flue gas]
Specific reboiler duty (steam) depending on solvent	3.5 – 4	[GJ/tCO_2]
Electric power requirement	Approx. 125	[MJ/tCO_2]
Plant water requirement, used in DCC and absorber	Approx. 0.5	[m^3/tCO_2]

Note: Solvent will be required to initially charge the system, continuous addition of solvent is however not expected to be required (given that it is recovered in the process). Fresh solvent is expected to be required based on the waste flue gas composition, performance of the EfW flue gas treatment system as well as solvent selection.

There are a range of suppliers offering carbon capture plants at various scales. One can typically divide the solutions into two options:

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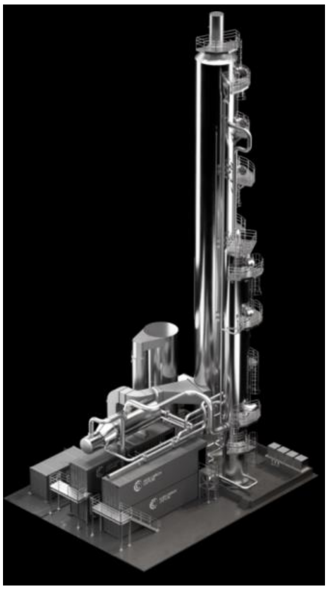
13 Solvent selection for carbon dioxide absorption - ScienceDirect
14 https://www.sciencedirect.com/science/article/pii/S1750583621001468
15 https://www.sciencedirect.com/science/article/pii/S1750583621001468
16 https://pure.hw.ac.uk/ws/files/27086714/1_s2.0_S1876610214019523_main.pdf

- Modular solutions: which are typically off the shelf and set to a standard throughput, so therefore more suitable to smaller throughputs or
- Tailored designs: which are specifically designed to match a facilities throughput

It is important to note that the majority of EfW plants in the UK have a capacity in the range of 100–500ktonne / annum of waste, and are therefore much larger than the Lerwick plant. The EfW facility and thus the subsequent carbon capture unit in Lerwick will be particularly small scale, leaning more to demonstration size and thus therefore more suited to the modular technology offerings. One such examples is the Just Catch™ by Aker Carbon Capture system which come in 40,000 and 100,000 tonne CO_2/annum units[17]. Other providers of small modular systems include CycloneCC[18] and C-Capture[19]. Various companies are also collaborating to commercialise CO_2 capture from EfW off-gases and are expected to be available to the market within the next 5 years[20].

Aker Carbon Capture unit



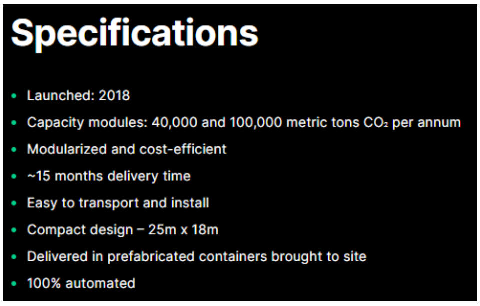


Figure 13-3 overview of Aker Carbon Capture's technology offering

A2.2.3 Methanol Synthesis Process

Synthesis of methanol is a commercial process that has been in use for 80 years using the Fischer-Tropsch process where synthesis gas (or syngas) reacts in the presence of a catalyst ($Cu/ZnO/Al_2O_3$)[21]. Coal was initially used as the main feedstock, more commonly it is now produced from natural gas (which serves as a source of both carbon and hydrogen). Direct methanol production from separately provided H_2 and CO_2 is less common (less than 0.2% globally[22]) but can be achieved by specific catalyst selection and is governed by the following reactions[23]:

- One step reaction:

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O \qquad \Delta H_{298K} = -49.16\ KJ/mol$$

- Two step reactions:

$$CO_2 + H_2 \leftrightarrow CO + H_2O \qquad \Delta H_{298K} = 41.21\ KJ/mol$$

17 Just Catch™ – Aker Carbon Capture
18 CycloneCC - Press Office - Newcastle University (ncl.ac.uk)
19 Waste to Energy - C-Capture
20 EfW carbon capture projects take step forward - letsrecycle.com
21 Conversion of carbon dioxide to methanol: A comprehensive review - ScienceDirect
22 Innovation Outlook: Renewable Methanol
23 https://www.sciencedirect.com/science/article/pii/S2212982017307862

$$CO + 2H_2 \leftrightarrow CH_3OH \qquad \Delta H_{298K} = -90.77\ KJ/mol$$

As the above reactions are in equilibrium, one needs to maintain the system at relatively high pressure and constant temperature. As this reaction is moderately exothermic (releases heat), one of the challenges associated with the process is removal of excess heat to ensure that the equilibrium is shifted towards the products and unwanted side reactions are avoided – which can result in catalyst sintering. Another key element that requires optimisation is the H_2/CO_2 ratio to ensure that the methanol yield is maximised, typically the optimum ratio is 4[24]. Fundamentally, methanol synthesis may be separated into three stages[25]:

1. feed gas compression up to the reactor feed pressure,
2. heating up of pressurised feed and feeding into the reactor and
3. depressurisation where unreacted gases are flashed off prior to the water / Methanol stream being routed to a distillation column for purification.

The water produced is a by-product of the process. Figure 13-4 provides a high-level overview of the process. Various optimisations and alternative flow sheets have been modelled and can be considered to optimise methanol production.

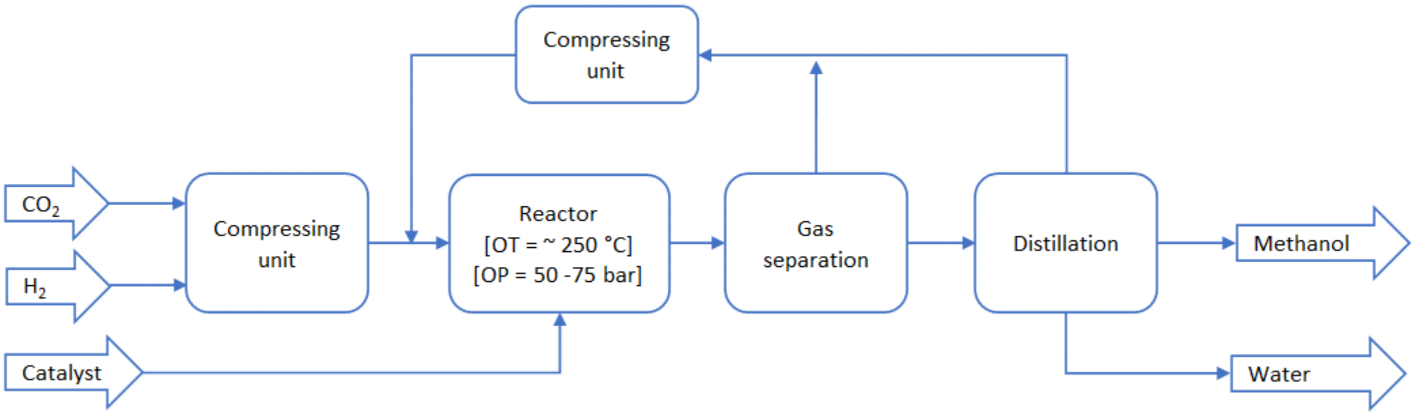


Figure 13-4 High level block flow diagram for Methanol production

The process is also energy intensive, in addition to the elements shown on the flow diagram – steam and cooling water are required to operate the unit (for reactor cooling and distillation of the water from the methanol). The conversion rate of CO_2 in the catalytic reactor is ~22%, as the unreacted gas is recycled back into the reactor an overall conversion of ~94%[26] is achieved. Table 11 provides an overview of the typical inputs and outputs required for the process to produce 1 tonne of methanol [27&28]

Table 11: Typical inputs / outputs required for methanol production from captured CO_2

Technological metric	Value	Units
Mass balance		
Inlet CO_2	1.46 – 1.7	Tonne / Tonne methanol
Inlet H_2	0.2 – 0.23	Tonne / Tonne methanol
Catalyst – depends on reactor & plant size	Life span → 4 years	
Outlet Methanol	1	Tonne / Tonne methanol
Outlet water	0.57 – 0.6	Tonne / Tonne methanol

24 https://www.sciencedirect.com/science/article/pii/S0306261920313052
25 https://www.sciencedirect.com/science/article/pii/S0306261915009071
26 https://www.sciencedirect.com/science/article/pii/S0306261915009071
27 https://www.sciencedirect.com/science/article/pii/S0306261915009071
28 https://www.mdpi.com/2227-9717/7/7/405

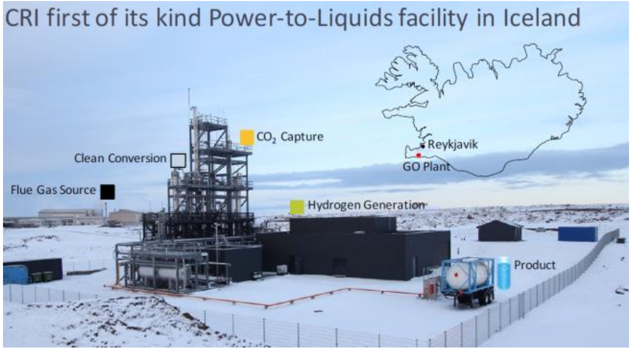
Technological metric	Value	Units
Utility Water requirement [steam & cooling water M/U]	Approx. 26	Tonne / Tonne methanol
Energy balance		
Electricity consumption	0.17 – 0.63	MWh / Tonne methanol
Heating requirements	0 – 0.439	MWh / Tonne methanol
Cooling requirements	0.86 – 3	MWh / Tonne methanol
Waste heat generated	0 – 2.7	MWh / Tonne methanol

From Table 11, assuming that 20,000 tonne/annum CO_2 is available and 90% is captured, one will have a feed rate of 18 000 tonne/annum CO_2. This could potentially be used to produce ~10,000 – 12,330 tonne/annum of methanol. Depending on the level of heat integration applied in the process and given that the overall reaction is exothermic, one could potentially generate a fair amount of waste heat, which, in the case of Lerwick could potentially be integrated in the district heating network. The corresponding CO_2 footprint is dependent on the electricity source used, if green electricity is used then the CO_2 used is equivalent to the CO_2 fed to the process.

It is noted that the expected facility size falls well below the typical average throughput of a commercial methanol facility. Companies such as Haldor Topsoe offer modularised methanol units (that typically use natural gas as feed)[29] with production outputs of ~100,000 tonne/annum methanol. Carbon Recycling International (CRI) is one of the few companies that has a demonstration unit that captures CO_2 (from geothermal sources), uses electrolysis for hydrogen production and then uses these to produce methanol[30]. Its demonstration unit had a production rate of 4,000 tonne/annum methanol, while its commercial unit[31], based in Shunli China, has a production rate of ~100,000 tonne/annum of methanol. A variety of additional technology providers have units that are due to come online soon[32]. It would therefore appear that although the production of methanol is well known there are a limited number of commercial facilities using captured CO_2 as a feedstock.

[29] http://meohtogo.com/2021%20MeOH-To-Go%20Fact%20Sheet%20300%20MTPD%20-%20US%20units.pdf
[30] https://www.co2value.eu/wp-content/uploads/2019/09/2.-CRI.pdf
[31] https://www.carbonrecycling.is/
[32] Innovation Outlook: Renewable Methanol

CRI – Methanol plant at Svartsengi, Reykjane



George Olah CO_2 to methanol plant, Orkubraut 2, Grindavik, Iceland
First commissioning: 2012
Capacity expansion: 2015
CCU throughput: 5,600 t/yr CO_2
Electrolyzer capacity: 800 t/yr H_2 (1200 Nm³/hr)
Production capacity: 4,000 t/yr methanol

Figure 13-5 Overview of CRI's methanol production demonstration facility

A2.3 Application to the Lerwick EfW

For the purposes of this high-level evaluation (and without assessing the CO_2 generated as a function of waste composition) one can assume that 1 tonne of Municipal Solid Waste (MSW) typically produces 900kgCO2[33]. For the Lerwick EfW facility, this equates to ~20,000 tonne/annum CO_2 being available for recovery from this facility. The heat recovered from this facility is used to supply the district heating network (the district heating network runs at ~95°C, with the supply from the EfW facility being 100–115°C). Given that excess heat is also produced by both CO_2 capturing and methanol production a potential opportunity exits to recover this heat for supply into the district heating network. The most likely process proposal for a methanol production facility at Lerwick is indicated in Figure 0-1, highlighting potential heat integration opportunities.

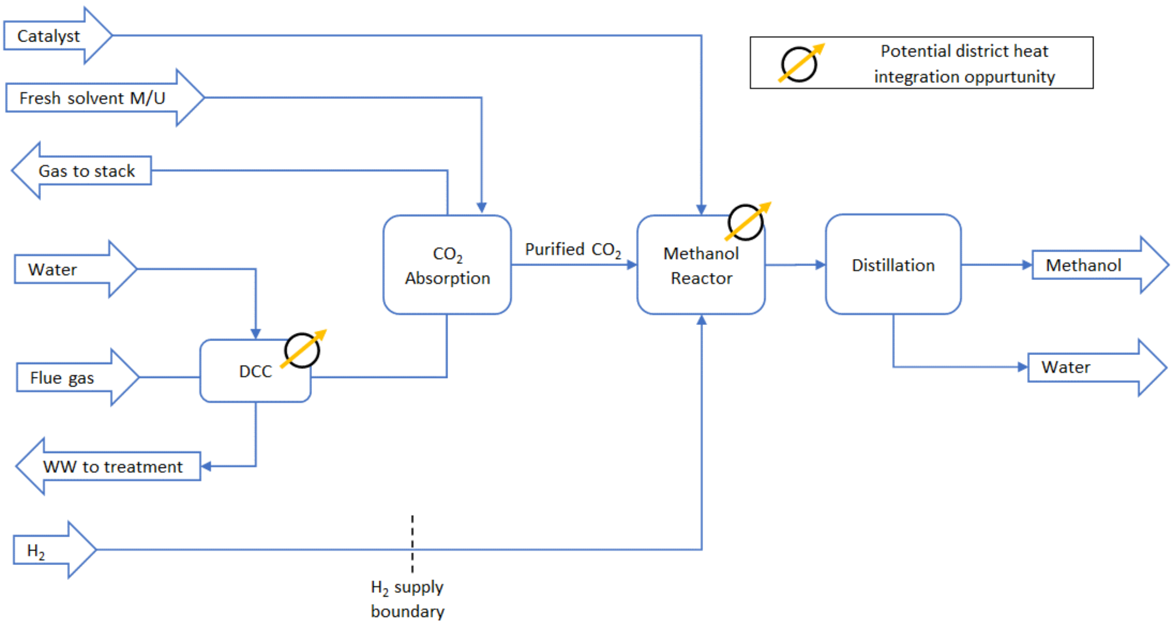


Figure 0-1 Potential process proposal for production of methanol from an integrated CO2 facility at Lerwick

It is understood that hydrogen will be produced via wind power and be readily available to the site. It is most likely that the carbon capture and methanol production facilities should be constructed near the vicinity of the Lerwick EfW facility to avoid the need to compress and transport the extracted CO_2. Figure 0-2 provides a mark-up of a potential change to the site that would be required to accommodate the new processing plants, based on an estimate of the various technology footprints:

[33] https://www.ieabioenergy.com/wp-content/uploads/2013/10/40_IEAPositionPaperMSW.pdf

Figure 0-2 Potential site layout for an integrated methanol production facility at Lerwick

A2.3.1 Inputs / Outputs

The typical inputs/outputs for this process are summarised in Table 12. Solvent and catalyst for the CO_2 capture and Methanol production respectively are not included as these will be required only on an intermittent basis.

Table 12 Estimated input / outputs for integrated CO2 capture / methanol production facility at Lerwick

a) CO_2 capture

Technical metric	Value [Estimate]
CO_2 in	***20,000 tonne/a***
Electric power requirement	~700 MWh/a
Cooling water requirement	~23,000 MWh/a
Plant water requirement	~11,000 m^3/a
Purified CO_2 product [CO_2 Captured]	~18,000 tonne/a

b) Methanol production

Technical metric	Value [Estimate]
H_2 feed	~2,500 tonne/a
Electricity consumption	2,100 – 7,000 MWh/a
Cooling water requirements	10,630 – 32,000 MWh/a
Plant water requirement	~ 300,000 m^3/a
Water production	6000 – 7000 m^3/a
Heating duty	0 – 5,500 MWh/a
Methanol product	***10,600 - 12,330 tonne/a***

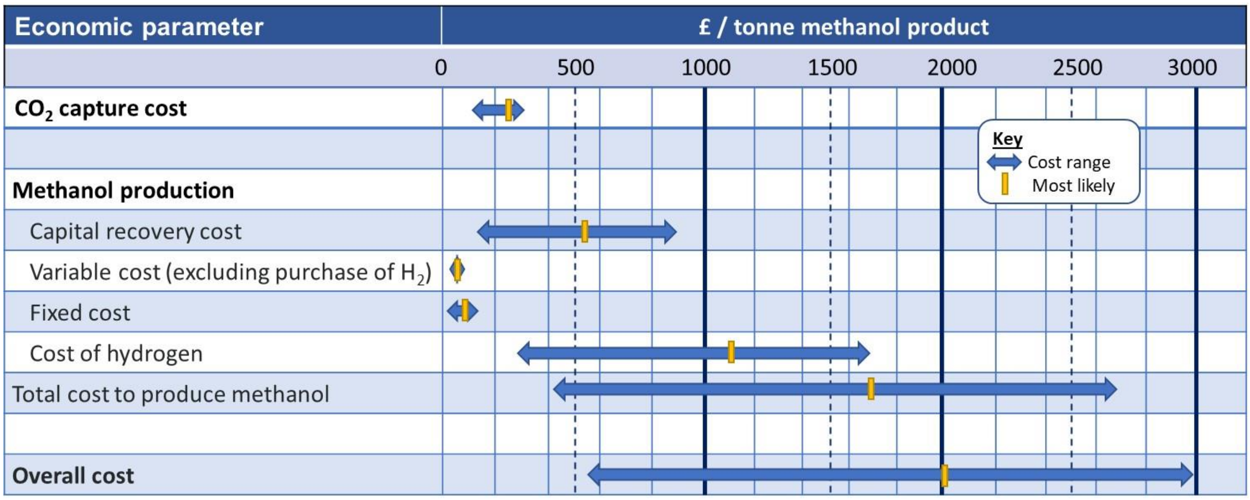
Table 12 illustrates that the process has a high energy and cooling water demand. Waste products that may be expected include spent solvent and catalyst that will require disposal, along with the water produced on the plant. There is a possibility to purify the water produced by the process and then to use it internally to the plant.

With a Net Calorific Value (NCV) of 19.9MJ/kg for methanol, the corresponding energy output represented by the methanol output is estimated to be ~68GWh/annum. Methanol could potentially replace a large fraction of the current Pelagic trawler demand which is currently estimated as ~100GWh/annum.

A2.3.2 Economics

The various references obtained in open literature indicated above and summarised in Section 0 can be used to compile a very high-level overview of the potential economics of this proposal for Shetland. The key assumptions used may be found in section A2.5.2.3 Assumptions. Information available provides an estimate of the CO_2 capture cost (i.e. both capital and operating). Capital costs for the methanol production facility require scaling (given that it is such a small unit), using the scaling method. The corresponding specific capital ranges available for the methanol production facility are very wide[34]: £1,500–7,250/tonne per annum of methanol, this information can be used to obtain capital recovery. Operating costs for the methanol facility are also available. Table 13 summarises the overall costs for the combined CO_2 capture and methanol production for the facility at Lerwick. The blue arrows illustrate the range of the costs and the yellow bars the most likely values.

Table 13 Estimated costs to establish and run a CO2 recovery / methanol production facility at Lerwick



From the Table 13 one can see that the highest cost contributor to the process is the methanol production facility. The cost of hydrogen, followed by the capital cost of the methanol production unit have the highest degree of variability and are the highest cost contributors. The methanol production unit has a much higher cost range than the CO_2 capture unit as commercial references running on a CO_2 and H_2 feed are relatively new the market, compared to their syngas counterparts. It can however be expected that as this technology becomes more widely applied the cost uncertainty will decrease. One of the current limitations of the current proposed scenario is the corresponding economy of scale of the methanol facility. If additional sources of CO_2 could be identified and transported to the Shetland islands or alternatively the captured CO_2 from Lerwick could be transported to a site with additional CO_2, then a larger methanol production facility could be considered. This would leverage off an improved economy of scale for the methanol production facility, thus making the lower ranges more obtainable.

Heat integration opportunities with the district heating network could be considered along with potential reductions in electricity prices. If one assumes that the full cooling duty (unlikely – given the high operating temperature of the network) could be used to expand the district heating network, an additional income of £~190/tonne methanol could potentially be realised, which could be used to displace the heat demand from the current oil system.

A2.3.3 SWOT Analysis

The table below considers the Strength, Weakness, Opportunities and Threats (SWOT) factors that are applicable to this proposal and should be considered in further detail, should the study be progressed to the following phase.

[34] Innovation Outlook: Renewable Methanol

Strength	Threat
• CO_2 absorption is a well-established technology with commercial references • Identification of alternative outlet for CO_2 and support for production of alternative (more transportable) fuel • Use of readily available source of hydrogen and renewable electricity	• The Lerwick EfW facility is 20 years old – i.e. close to end of life. Additional works have been carried out on the facility, but the facility may require additional maintenance.
Opportunity	**Weakness**
• Heat integration could be used (in the direct contact cooler during CO_2 capturing and from the exothermic methanol reactor) to expand the district heating network. • The water generated in the methanol production process could be purified and reused as make-up water • Consider importing additional CO_2 or exporting CO_2 generated at Lerwick to larger methanol production facility to reduce impact of economy of scale and overall costs • Smaller capacity potentially suited to commercial demonstration plant that might be eligible for Scottish or UK Government support for technology demonstration. • The economics can potentially be improved by considering including CO_2 credits as well as potential incentives for production of second-generation methanol	• Process has overall high electrical consumption • Economy of scale: Relatively small EfW facility with corresponding low CO_2 and methanol production facility (concern about proven at lower throughputs) • Alternative technology considerations: Given the plant lifetime alternative technologies could be considered these include gasification of the waste to then produce syngas which can then be converted to methanol (e.g. Enerkem[35]). • The technology offering for methanol production from CO_2 has a limited number of commercial references, as this increases the costs associated with methanol production can be expected to decrease.

A2.4 Summary

The capture of CO_2 from the EfW facility at Lerwick and then the subsequent conversion to methanol is a technically viable option with commercial references for both CO_2 capture from EfW and methanol production from the captured CO_2. The clear benefits of methanol production, as opposed to hydrogen, is the supply of an easy to transport fuel and the co-capture of CO_2. The methanol produced would also go a long way to replacing the current fuel demands of the native marine fleet. The physical EfW site at Lerwick does also seem to lend itself to accommodate such a facility. One of the main shortcomings of this option is however the economics. There is currently a high degree of uncertainty surrounding the costs of hydrogen and the capital cost of the methanol production facility. The economy of scale associated with the methanol production facility, which is traditionally at least 100,000 tonne methanol / annum compared to the potential production at Lerwick of ~12,500 tonne methanol/annum is also a key cost driver. A potential optimisation, to leverage the economy of scale on the methanol production unit, is to identify additional sources of CO_2 to increase the unit's throughput. Additional benefits such as the recovery of heat from the facility (through heat integration) to expand into the district heating network are a possibility that can be further investigated to improve the business case. A more detailed study is recommended if more accurate costs are required.

[35] Technology Comparison | Chemical Recycling | Enerkem

A2.5 Supporting Information

A2.5.1 High-level mass balance over the EfW facility in Lerwick

The table below provides a high-level mass balance over the Energy recovery Plant in Lerwick:

Element	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Average
Waste feed [tonnes]	21,994	22,750	22,849	23,653	23,561	23,056	23,453	22,958	22,785	22,097	21,411	22,845	22,784
Metal recovery [tonnes]	267	233	273	324	300	337	317	355	345	364	291	311	312
Hours of operation	8,006	8,121	7,942	8,251	8,062	7,909	8,121	8,160	7,922	8,103	7,616	7,986	8,017
Daily average [MW/h]	6.3	6.3	6.3	6.3	6.3	6.3	6.4	6.4	6.3	6.3	6.3	6.3	6.3

A2.5.2 Economic inputs

A2.5.2.1 CO_2 capture

Various references are available that provide a high-level estimate of the costs associated with the capture of CO_2. Two of the key elements that play[36] a role in the cost of the carbon capture facility are:

- The partial pressure (or concentration) of the CO_2 available (as this affects the size of the equipment), with partial pressures of at least 4kPa being preferable, after which
- The scale being the secondary driver (with a capture capacity tipping point of 0.3 MtonneCO_2/annum – where capacities below this scale, costs are expected to drastically increase (noting that Lerwick EfW will provide 0.02 MtonneCO_2/annum)

All references used referred to a capture cost, this is calculated using the following correlations:

$$Annualised\ CAPEX\left(\frac{£}{yr}\right) = \frac{CAPEX}{Annualised\ factor}$$

$$Annualised\ factor = \sum_{i=1}^{n}\left[\frac{1}{(1+r)^n}\right]$$

$$Total\ Annual\ Cost\left(\frac{£}{yr}\right) = Annualised\ CAPEX\left(\frac{£}{yr}\right) + Annualised\ OPEX\left(\frac{£}{yr}\right)$$

$$CO_2 captured\ cost\left(\frac{£}{tCO_2}\right) = \frac{Total\ Annual\ Cost\ (TAC)\left(\frac{£}{y}\right)}{Mass\ of\ CO_2\ captured\ \left(\frac{t}{y}\right)}$$

Where a discount rate (r) of 8% was used for an operational plant lifetime of (n) 25 years

One reference[37] advises that for CO_2 recovery from waste or biomass fired power units a capture cost of £50–65/tonne CO_2 [original reference: $60–80/tonne CO_2, 2020 Based estimate using ACCE with an estimated accuracy of ±40%]. This is in line with a second reference[38] that reports capture costs being in the range of between £57–70/tonne of CO_2 [€67–80/tonne CO_2 based in 2021]. It is however important to note that modular units, that are expected to be more appropriate to retrofit on the back end of Lerwick, will be negatively impacted by the economy of scale. The associated range for such a unit is potentially to £73–232/tonne CO_2 [$95-300/tonne of CO_2 in original reference]. One could however expect that as the technology develops, costs to decrease.

A2.5.2.2 Methanol production

The study completed by Pérez-Fortes, et al. (2016)[39] and Szima & Cormos (2018) concluded that the production costs of the facility were relatively high making the overall project financially unattractive. The project could potentially become viable if the methanol value were to double or the hydrogen costs were to drastically decrease. Since the study methanol prices have slightly increase but hydrogen prices have not really changed. The table below summarises the costs that were obtained (noting that the assumptions used may vary – e.g. interest rate, inclusion of hydrogen storage, cost of electricity/other utilities and plant lifetime) in those two articles. One of the main contributors to the cost is the hydrogen costs (either the production or the purchase thereof, highlighted below).

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[36] Technology-Readiness-and-Costs-for-CCS-2021-1.pdf (globalccsinstitute.com)
[37] Technology-Readiness-and-Costs-for-CCS-2021-1.pdf (globalccsinstitute.com)
[38] Capital cost estimation of CO2 capture plant using Enhanced Detailed Factor (EDF) method: Installation factors and plant construction characteristic factors - ScienceDirect
[39] https://www.sciencedirect.com/science/article/pii/S0306261915009071

Table 14: Overview of methanol production economics

Facility size	Ref year	Methanol production cost	2022	Original values
440 ktonne methanol/ annum[40]	2016	CAPEX = €220 million. Specific capital cost: £500/tonne per year Methanol [€451.16/tonne Methanol in 2016]		
			2022	2016 – original values
		Variable cost (including purchase of H_2)	£600/tonne methanol	€641.5/tonne Methanol
		Variable cost (excluding purchase of H_2)	£25/tonne methanol	€27/tonne Methanol [H_2 = €3090/tonne Methanol]
		Fixed costs (salaries	£23/tonne methanol	€25/tonne Methanol
		Revenue		€400/tonne Methanol[41]:
100 ktonne methanol/ annum[42]	2018	CAPEX = 60 M€. Specific capital cost: £550/tonne per year Methanol [€ 555.6/ tonne Methanol in 2018]		
			2022	2018 – original values
		Variable cost (including electricity cost to produce H_2)	£610/tonne methanol	€670.5/tonne Methanol
		Variable cost (excluding electricity cost to produce H_2)	£40/tonne methanol	€43/tonne Methanol [H_2 = €3090/tonne Methanol]
		Fixed costs (salaries	£106/tonne methanol	€115/tonne Methanol
		Revenue		€500/tonne Methanol[43]

As with most technologies, economy of scale will play a key role in the capital cost of a facility. The corresponding capital cost for a smaller unit may be calculated by using the following correlation:

$$Captial\ cost\ capacity\ B = Captial\ cost\ capacity\ A \times \left(\frac{Capacity\ B}{Capacity\ A}\right)^{n}$$, Where n is typically 0.6

Production of methanol from conventional feedstocks, such as natural gas and coal is expected to be cheaper than production of methanol from captured CO_2[44]. A study was completed in 2007 for a 18,200 tonne/annum methanol production facility (feeding in 31,100 tonne/annum CO_2) a production cost of £782/tonne methanol [original reference: €963/tonne methanol was quoted[45]]. This is noted to include the costs associated with purchasing of CO_2 and hydrogen. This value is noted to be much higher than that of larger facilities. The study completed by IRENA (2021)[46] provided four references for capital costs for facilities producing methanol from CO_2 and H_2. The specific capital cost was typically between £1,500-£3,730/tonne per annum of methanol [original reference: $2,000 – 5,000/tonne per annum of methanol], with one outlier case for a 4,000 tonne/annum facility of £7,250/tonne per annum of methanol [original reference $9,720/tonne per annum of methanol].

[40] https://www.sciencedirect.com/science/article/pii/S0306261915009071
[41] Assumed value of methanol was €400 / ton, the current price is € 505 / ton Pricing | Methanex Corporation
[42] https://www.sciencedirect.com/science/article/pii/S2212982017307862
[43] Assumed value of methanol was €400 / ton, the current price is € 505 / ton Pricing | Methanex Corporation
[44] https://dspace.lib.cranfield.ac.uk/bitstream/handle/1826/1449/Renewable%20Hydrogen-Methanol-2007.pdf;sequence=1
[45] https://www.mdpi.com/2227-9717/7/7/405/htm
[46] Innovation Outlook: Renewable Methanol

A2.5.2.3 Assumptions

The following exchange rates have been used for conversions:

1. Pound to dollar exchange rate [£1 = $1.34]
2. Pound to euro exchange rate [£1 = €1.23]

The following assumptions were considered for the compilation of the economics:

- No additional gas clean-up is required on the off gases exiting the EfW facility prior to capture of CO_2.
- Electricity is readily available (it is understood that electricity will be available at potentially a lower cost, this is currently not accounted for in the calculations and will require correction should the study proceed further)
- No credit is taken for replacement of existing fleet fuel
- No fee is associated with CO_2 (as it is considered to be internal production)
- No credit is taken for the CO_2 captured
- Hydrogen, CO_2 and methanol storage is excluded
- An income from increasing the district heating network could potentially be generated at 6.9p per kWh[47]

[47] Domestic Tariffs | Shetland Heat Energy & Power (sheap-ltd.co.uk)

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